its notice in the **Federal Register**, subject to its tariff publication effective date.

HG-5-79 (Special Certificate—Used Household Goods), filed April 29, 1979. Applicant: EIGHMIE MOVING & STORAGE CO., INC., Route 9W, Milton, NY 12547. Representative: Alvin Altman, 888 Seventh Ave., New York, NY 10019. Authority sought: Between points in Dutchess, Orange, Putnam, Rockland, Sullivan, Ulster, and Westchester Counties, NY, and Fairfield County, CT, serving the United States Military Academy, West Point, NY.

HG-6-79 (Special Certificate—Used Household Goods), filed May 4, 1979. Applicant: NAUM MOVING & STORAGE CO., INC., 5994 Wilbur Road, East Syracuse, NY 13057. Representative: Gingold & Gingold, 824 University Bldg., Syracuse, NY 13202. Authority sought: Between points in Onandaga, Madison, Oswego, Cortland, Cayuga, Oneida, Lewis, Jefferson, and St. Lawrence Counties, NY, serving Hancock Air Force Base, Syracuse, NY, and Griffis Air Force Base, Rome, NY.

HG-7-79 (Special Certificate—Used Household Goods), filed May 8, 1979. Applicant: SECURITY WAREHOUSES, INC., 40 Robert Pitt Drive, Monsey Drive, NY 10952. Representative: Alvin Altman, 888 Seventh Ave., New York, NY 10019. Authority Sought: Between points in Dutchess, Orange, Putnam, Rockland, Ulster, and Westchester Counties, NY, and Fairfield County, GT, serving the United States Military Academy, West Point, NY.

HG-8-79 (Special Certificate—Used Household Goods), filed May 17, 1979. Applicant: UNITED MOVING AND STORAGE, INC. OF DAYTON, 1728 Troy St., Dayton, OH 45404. Representative: Earl N. Merwin, 85 East Gay St., Columbus, OH 43215. Authority Sought: (1) Between points in Allen, Auglaise, Butler, Champaign, Clark, Clinton, Darke, Defiance, Fayette, Fulton, Greene, Hancock, Highland, Harden, Henry, Logan, Mercer, Miami, Montgomery, Paulding, Preble, Putnam, Shelby, Van Wert, Warren, and Williams Counties, OH, serving Wright-Patterson Air Force Base, OH, and (2) between points in Adams, Brown, Clermont, and Hamilton Counties, OH, and Anderson, Bath, Bell, Boone, Burbon, Boyd, Boyle, Bracken, Breathitt, Campbell, Carter, Clark, Clay, Elliott, Estill, Fayette, Fleming, Floyd, Franklin, Gallitan, Garrard, Grant, Greenup, Harlan, Harrison, Jackson, Jessamine, Johnson, Kenton, Knott, Knox, Laurel, Lawrence, Lee Leslie, Letcher, Lewis, Lincoln, McCreary, Madison, Magoffin, Martin, Mason, Menifee, Mercer, Montgomery, Morgan, Nicholas, Owen, Owsley, Pendleton, Perry, Pike, Powell, Pulaski, Robertson, Rockcastle, Rowan, Scott, Whitely, Wolfe, and Woodford Counties, KY, serving Red River Army Depot, Texarkana, TX.

By the Commission.

H. G. Homme, Jr.,

Secretary.

[FR Doc. 79-18075 Filed 6-8-79; 8:45 am]

BILLING CODE 7035-01-M

[Notice No. 85]

Motor Carrier Temporary Authority Applications

May 22, 1979.

The following are notices of filing of applications for temporary authority under Section 210a(a) of the Interstate Commerce Act provided for under the provisions of 49 CFR 1131.3. These rules provide that an original and six (6) copies of protests to an application may be filed with the field official named in the **Federal Register** publication no later than the 15th calendar day after the date the notice of the filing of the application is published in the **Federal Register**. One copy of the protest must be served on the applicant, or its authorized representative, if any, and the protestant must certify that such service has been made. The protest must identify the operating authority upon which it is predicated, specifying the "MC" docket and "Sub" number and quoting the particular portion of authority upon which it relies. Also, the protestant shall specify the service it can and will provide and the amount and type of equipment it will make available for use in connection with the service contemplated by the TA application. The weight accorded a protest shall be governed by the completeness and pertinence of the protestant's information.

Except as otherwise specifically noted, each applicant states that there will be no significant effect on the quality of the human environment resulting from approval of its application.

A copy of the application is on file, and can be examined at the Office of the Secretary, Interstate Commerce Commission, Washington, D.C., and also in the ICC Field Office to which protests are to be transmitted.

Note.—All applications seek authority to operate as a common carrier over irregular routes except as otherwise noted.

Motor Carriers of Property

MC 3854 (Sub-49TA), filed April 17, 1979. Applicant: BURTON LINES, INC., P.O. Box 11306 East Durham Station, Durham, NC 27703. Representative: G.E. Martin, Jr., 815 Ellis Road, Durham, NC 27703. *Composition board, insulating boards and building materials* from the facilities of Celotex Corporation at Pennsauken, NJ to points in AL, FL, GA, KY, NC, SC, TN, and WV for 180 days. An underlying ETA seeking 90 days authority has been filed. Supporting shipper(s): Jim Walter Corporation 1500 North Dale Mabry Highway, Tampa, FL 33607. Send protests to: Mr. Archie W. Andrews, District Supervisor, ICC, P.O. Box 26896, Raleigh, NC 27611.

MC 14215 (Sub-35TA), filed April 13, 1979. Applicant: SMITH TRUCK SERVICE, INC., P.O. Box 1329, Steubenville, OH 43952. Representative: John L. Alden, 1396 W. Fifth Ave., Columbus, OH 43212. *Iron and steel and iron and steel articles*, from Beaver Falls, PA to points in CT, GA, IN, IL, KY, NC, NJ, OH, SC, TN, VA, and the lower peninsula of MI, for 180 days. Supporting shipper(s): Moltrup Steel Products Company, P.O. Box 331, Beaver Falls, PA 15010. Send protests to: J. A. Niggemyer, DS, 416 Old P.O. Bldg., Wheeling, WV 26003.

MC 59655 (Sub-21TA), filed April 23, 1979. Applicant: SHEEHAN CARRIERS, INC., 62 Lime Kiln Road, Suffern, NY 10901. Representative: George A. Olsen, POB 357, Gladstone, NJ 07934. *(1) Glass containers and (2) materials, equipment and supplies used in the manufacture and distribution of containers, container ends and closures (except commodities in bulk)*, between points in ME, NH, VT, MA, CT, RI, NY, NJ, PA, DE, MD, VA, WV, and DC. Restricted to the transportation of traffic originating at or destined to the facilities and warehouse sites of National Bottle Company located in the above-described territory, for 180 days. Supporting shipper(s): National Bottle Company, One Bala Cynwyd Plaza, Bala Cynwyd, PA 19004. Send protests to: Maria B. Kejss, Transportation Assistant, Interstate Commerce Commission, 26 Federal Plaza, New York, N.Y. 10007.

MC 98614 (Sub-8TA), filed April 2, 1979. Applicant: ARKANSAS TRANSPORT COMPANY, P.O. Box 702, Little Rock, AR 72203. Representative: Roland M. Lowell, 618 United American Bank Bldg., Nashville, TN 37219. Petroleum and petroleum products, in bulk, from Union, Ouachita, and Calhoun Counties, AR to points in LA (except New Orleans and its commercial zone) for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Gasoline Marketers, Inc., 6301 Centennial Blvd., Nashville, TN 37202; Southern Farmers Association, P.O. Box 5489, North Little Rock, AR 72119. Send protests to: William H. Land, Jr., District Supervisor, 3108 Federal Office Building, 700 West Capitol, Little Rock, AR 72201.

MC 107295 (Sub-917TA), filed April 11, 1979. Applicant: PRE-FAB TRANSIT CO., P.O. Box 146, Farmer City, IL 61842. Representative: Richard Vollmer, (same address as applicant). Common Irregular: *Commodities* (except in bulk) used in the manufacture and distribution of building materials as described in Appendix VI of the report in Descriptions in Motor Carrier Certificates 61 MCC 209, and wall board, hardboard, insulation and padding and cushioning materials, mulch firewood, and nonwoven fibers from points in AL, AK, FL, GA, IL, IN, KS, LA, MI, MS, MO, NE, NC, OH, OK, SC, TN, TX, WI to the plantsite of Conwed Corporation at Cloquet, MN, for 180 days. An underlying ETA seeks 90 day authority. Supporting shipper(s): Conwed Corporation, Cloquet, MN 55720. Send protests to: Charles D. Little, District Supervisor, Interstate Commerce Commission, Room 414, Leland Office Building, 527 East Capitol Avenue, Springfield, IL 62701.

MC 107515 (Sub-1228TA), filed March 21, 1979. Applicant: REFRIGERATED TRANSPORT CO., INC., P.O. Box 308, Forest Park, GA 30050. Representative: Alan E. Serby & Richard M. Tettelbaum, Serby & Mitchell, Fifth Floor, Lenox Towers South, 3390 Peachtree Rd., NE., Atlanta, GA 30326. *Such commodities as are dealt in by drug stores and cosmetic dealers (except commodities in bulk), in vehicles equipped with mechanical refrigeration*, from facilities of Clairol, Inc., at or near Stamford, CT, to Camarillo and LaMirada, CA; Atlanta, GA; Chicago, IL; Indianapolis, IN; Portland, OR; and Dallas, TX, and points in their respective commercial zones, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Clairol, Inc., One Blachley Rd., Stamford, CT 06901. Send protests to: Sara K. Davis, TA, ICC, 1252 W. Peachtree St., NW, room 300, Atlanta, GA 30309.

MC 107515 (Sub-1229TA), filed March 22, 1979. Applicant: REFRIGERATED TRANSPORT CO., INC., P.O. Box 308, Forest Park, GA 30050. Representative: Alan E. Serby & Richard M. Tettelbaum, Fifth Floor, Lenox Towers South, 3390 Peachtree Road, NE., Atlanta, GA 30326. *Canned foodstuffs, in mechanically refrigerated equipment*, from facilities of Glorietta Foods, at or near Hollister, Oakland and San Jose, CA to points in IL, IN, IA, KS, MN, MO, NE, NY, OH, PA and WI for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Glorietta Foods, P.O. Box 5040, San Jose, CA 95150. Send protests to: Sara K. Davis, T/A, ICC, 1252 W. Peachtree St. NW., Rm. 300, Atlanta, GA 30309.

MC 107515 (Sub-1230TA), filed April 5, 1979. Applicant: REFRIGERATED TRANSPORT CO., INC., P.O. Box 308, Forest Park, GA 30050. Representative: Richard M. Tettelbaum, Serby & Mitchell, 3390 Peachtree Rd., NE., Suite 520, Atlanta, GA 30326. *Meat, meat products, meat by-products and articles distributed by meat packinghouses (except commodities in bulk) as described in Sections A and C of Appendix I to the report in Descriptions in Motor Carrier Certificates, 61 M.C.C. 209 and 766 when moving in mechanically refrigerated vehicles* from the facilities of or utilized by Oscar Mayer & Co., Inc. at Madison, WI to Los Angeles, CA and points in its Commercial Zone, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Oscar Mayer & Co., Inc., P.O. Box 7188, Madison, WI 53707. Send protests to: Sara K. Davis, TA, ICC, 1252 W. Peachtree St. NW., Rm. 300, Atlanta, GA 30309.

MC 111274 (Sub-41TA), filed April 18, 1979. Applicant: SCHMIDGALL TRANSFER, INC., P.O. Box 356, RR No. 2, Morton, IL 61550. Representative: Elmer C. Schmidgall (same address as applicant). Contract irregular: *Milk and milk products and containers* for same (except in bulk, in tank vehicles) between Peoria, IL and Logansport, IN, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Producers Dairy Division of Prairie Farms Dairy, Inc., 2000 North University, Peoria, IL 61601. Send Protests to: Charles D. Little, District Supervisor, Interstate Commerce Commission, Room 414 Leland Office Building, 527 East Capitol Avenue, Springfield, IL 62701.

MC 115654 (Sub-143TA), filed April 12, 1979. Applicant: TENNESSEE CARTAGE CO., INC., P.O. Box 23193, Nashville, TN 37202. Representative: Hank Seaton, 929 Pennsylvania Bldg., 425 Thirteenth St. NW., Washington, DC 20004. *Foodstuffs, and materials, supplies, ingredients, and equipment used in the manufacture of frozen foods*, between the facilities of Morton Frozen Foods, at or near Russellville and Searcy, AR on the one hand, and, on the other, points in AL, GA, IL, IN, KY, MI, MS, OH, TN, and LA, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Morton Frozen Foods Division, ITT Continental Baking Co., Inc., One Morton Drive, Charlottesville, VA 22906. Send protests to: Glenda Kuss, TA, ICC, Suite A-422, U.S. Court House, 801 Broadway, Nashville, TN 37203.

MC 117815 (Sub-297TA), filed April 5, 1979. Applicant: PULLEY FREIGHT LINES, INC., 405 S.E. Twentieth St., Des Moines, IA 50317. Representative: Jack H. Blanshan, Suite 200, 205 W. Touhy Ave., Park Ridge, IL 60068. (1) *Meats, meat products, meat by-products, and articles distributed by meat packing houses* as described in Sections A and C of Appendix I to the report in Descriptions in Motor Carrier Certificates, 61 M.C.C. 209 and 766 (except hides and commodities in bulk) and (2) *Foodstuffs* when moving mixed loads with articles listed in (1) above, from the facilities of Oscar Mayer & Co. at or near Madison, WI to Goodlettsville, TN for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Oscar Mayer & Co. Inc., P.O. Box 7188, Madison, WI 53707. Send protests to: Herbert W. Allen, DS, ICC, 518 Federal Bldg., Des Moines, IA 50309.

MC 117815 (Sub-298TA), filed April 6, 1979. Applicant: PULLEY FREIGHT LINES, INC., 405 S.E. 20th St., Des Moines, IA 50309. Representative: Jack H. Blanshan, Suite 200, 205 W. Touhy Ave., Park Ridge, IL 60068. *Materials, equipment and supplies used by canning factories and frozen food manufacturers* (except commodities in bulk), from points in IL, IN, IA, KS, MI, MO, NE, and WI and Memphis, TN and Fargo, ND and points in their respective commercial zones to the facilities of Jeno's, Inc. at Duluth, MN and its commercial zone for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Jeno's, Inc., 525 Lake Ave. South, Duluth, MN 55801. Send protests to: Herbert W. Allen, DS, ICC, 518 Federal Bldg., Des Moines, IA 50309.

MC 117815 (Sub-299TA), filed April 6, 1979. Applicant: PULLEY FREIGHT LINES, INC., 405 S.E. 20th St., Des Moines, IA 50317. Representative: Jack H. Blanshan, Suite 200, 205 W. Touhy Ave., Park Ridge, IL 60068. *Such commodities as are dealt in by wholesale and retail food and drug outlets* (except commodities in bulk), from the facilities of Procter & Gamble Distributing Company at Iowa City and Riverdale, IA and their respective commercial zones to Kansas City and

Topeka, KS and their respective commercial zones, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Procter & Gamble Distributing Company, P.O. Box 599, Cincinnati, OH 45201. Send protests to: Herbert W. Allen, DS, ICC, 518 Federal Bldg., Des Moines, IA 50309.

MC 117815 (Sub-300TA), filed April 13, 1979. Applicant: PULLEY FREIGHT LINES, INC., 405 S.E. 20th St., Des Moines, IA 50317. Representative: Jack H. Blanshan, Suite 200, 205 W. Touhy Ave., Park Ridge, IL 60068. *Paper, paper products, cellulose products, and textile softeners* (except commodities in bulk) from the facilities of Procter & Gamble Paper Products at Green Bay, WI and its commercial zone to IL, IN, IA, KS, MI, MN, MO and NE for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Procter & Gamble Paper Products Company, P.O. Box 599, Cincinnati, OH 45201. Send protests to: Herbert W. Allen, DS, ICC, 518 Federal Bldg., Des Moines, IA 50309.

MC 117815 (Sub-301), filed April 20, 1979. Applicant: PULLEY FREIGHT LINES, INC., 405 S.E. 20th St., Des Moines, IA 50317. Representative: Jack H. Blanshan, Suite 200, 205 W. Touhy Ave., Park Ridge, IL 60068. *Paper and paper products* from the facilities of Samson-Midamerica located at Indianapolis, IN and its commercial zone to points in IA for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Samson-Midamerica, 8111 Zionsville, Indianapolis, IN 46268. Send protests to: Herbert W. Allen, DS, ICC, 518 Federal Bldg., Des Moines, IA 50309.

MC 120924 (Sub-8TA), filed March 16, 1979. Applicant: B & W CARTAGE CO., 2932 West 79th Street, Chicago, IL 60652. Representative: Hamlin A. Smith, 2932 West 79th Street, Chicago, IL 60652. *Auto parts*, NOI, between Chicago, IL and Detroit, MI for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Chrysler Corporation, P.O. Box 1976, Detroit, MI 48288. Send protests to: Annie Booker, Transportation Assistant, Interstate Commerce Commission, 219 South Dearborn Street, Room 1386, Chicago, IL 60604.

MC 121664 (Sub-71TA), filed April 11, 1979. Applicant: HORNADY TRUCK LINE, INC., P.O. Box 846, Monroeville, AL 36460. Representative: W. E. Grant, 1702 First Avenue South, Birmingham, AL 35201. *Roofing and roofing materials*, from Holt, Al, and its commercial zone, to points in MS, TN, KY, GA, NC, SC, FL, AL, LA, AR, VA, MO, IL, and IN, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Warrior Roofing Manufacturing Co., Inc., P.O. Box 3161, Tuscaloosa, AL 35401. Send protests to: Mabel E. Holston, T/A, ICC, Room 1616, 2121 Building, Birmingham, AL 35203.

MC 123115 (Sub-21TA), filed April 26, 1979. Applicant: PACKER TRANSPORTATION CO., 465 South Rock Boulevard, Sparks, NV 89431. Representative: Robert G. Harrison, 4299 James Drive, Carson City, NV 89701. *Fiberglass Ceiling Tile* from the facilities of Owens-Corning Fiberglas Corp. at St. Helens, OR to points in NV, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Owens-Corning Fiberglas Corp., Fiberglas Tower, Toledo, OH 43659. Send protests to: W. J. Huetig, D.S., I.C.C. 203 Federal Building, 705 North Plaza St., Carson City, NV 89701.

MC 123255 (Sub-204 TA), filed February 27, 1979. Applicant: B & L MOTOR FREIGHT, INC., 1984 Coffman Road, Newark, Ohio 43055. Representative: C. F. Schnee, Jr., 1984 Coffman Road, Newark, Ohio 43055. *Kitchen cabinets, vanities and related articles used in the installation thereof* from the facilities of Delmar Corporation a division of Triangle Pacific Corporation at or near Union City, IN to points in CT, DE, ME, MD, MA, NH, NJ, NY, OH, PA, RI, VT, VA, WV, and the District of Columbia for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Delmar Corporation, a Division of Triangle Pacific Corporation, 4255 LBJ Freeway, Dallas, Texas 75234. Send protests to: Frank L. Calvary, District Supervisor, Interstate Commerce Commission, 220 Federal Building and U.S. Courthouse, 85 Marconi Boulevard, Columbus, Ohio 43215.

MC 123255 (Sub-205 TA), filed March 6, 1979. Applicant: B & L MOTOR FREIGHT, INC., 1984 Coffman Road, Newark, Ohio 43055. Representative: C. F. Schnee, Jr., 1984 Coffman Road, Newark, Ohio 43055. *Paper and paper products (except commodities in bulk)* from the facilities of The Mead Corporation located at or near Kingsport and Gray, TN to points in CT, ME, MA, NH, NJ, NY, PA, RI, and VT for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): The Mead Corporation, Courthouse Plaza, Northeast, Dayton, Ohio 45463. Send protests to: Frank L. Calvary, District Supervisor, Interstate Commerce Commission, 220 Federal Building and U.S. Courthouse, 85 Marconi Boulevard, Columbus, Ohio 43215.

MC 123255 (Sub-206 TA), filed March 20, 1979. Applicant: B & L MOTOR FREIGHT, INC., 1984 Coffman Road, Newark, Ohio 43055. Representative: C. F. Schnee, Jr., 1984 Coffman Road, Newark, Ohio 43055. *Mineral wool* (clay, rock, slag, or glass wool) from the facilities of Guardian Insulation Division of Guardian Industries, Inc. at or near Albion, Mi to points in IL, IN, IA, MI, MN, NY, OH, PA, and WI for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Guardian Insulation Division Guardian Industries, 701 N. Broadway, Huntington, IN 46750. Send protests to: ICC Wm. J. Green, Jr. Federal Bldg., 600 Arch Street, Rm. 3238, Philadelphia, PA 19106.

MC 123255 (Sub-207 TA), filed March 30, 1979. Applicant: B & L MOTOR FREIGHT, INC., 1984 Coffman Road, Newark, Ohio 43055. Representative: C. F. Schnee, Jr., 1984 Coffman Road, Newark, Ohio 43055. *Glass containers and closures therefor* from Muncie, IN to Gloucester City, NJ. for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Ball Coprporation, 345 Sought High Street, Muncie, IN 47302. Send protests to: ICC Wm. J. Green, Jr. Federal Bldg., 600 Arch Street, Philadelphia, PA 19106.

MC 123255 (Sub-208TA), filed March 30, 1979. Applicant: B & L MOTOR FREIGHT, INC., 1984 Coffman Road, Newark, Ohio 43055. Representative: C. F. Schnee, Jr., 1984 Coffman Road, Newark, Ohio 43055. *(1) Containers, container ends and closures (2) commodities manufactured or distributed by manufacturers and distributors of containers when moving in mixed loads with containers, (3) materials, equipment and supplies used in the manufacture and distribution of containers, container ends and closures* (except commodities in bulk) between Lexington KY on the one hand and on the other points in the States of IL, IN, MI and OH, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): American Can Company, American Lane, Greenwich, CT 06830. Send protests to: ICC, Wm. J. Green, Jr., Federal Bldg., 600 Arch Street, Philadelphia, PA 19106.

MC 123375 (Sub-17TA), filed April 24, 1979. Applicant: KIRK TRUCKING SERVICE, INC., 3100 Braun Avenue, Murrysville, PA 15668. Representative: A. Charles Tell, 100 East Broad Street, Columbus, OH 43215. *Gypsum products* from Buchanan, NY to all points in CT, MA, NJ, PA and RI for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Georgia-Pacific

Corporation, 1062 Lancaster Avenue, Rosemont, PA 19010. Send protests to: J. J. England, DS, ICC, 2111 Fed. Bldg., Pittsburgh, PA 15222.

MC 124174 (Sub-145TA), filed April 3, 1979. Applicant: MOMSEN TRUCKING CO., 13811 L St., Omaha, NE 68137. Representative: Karl E. Momsen (same address as applicant). *Castings and forgings*, from points in WI, IN, and MI to Omaha, NE; Joplin, MO; and Searcy, AR, for 180 days. Supporting shipper(s): L. J. Frederick, Sperry Vickers, 6600 North 72nd St., Omaha, NE 68122. Send protests to: Carroll Russell, ICC, Suite 620, 110 No. 14th St., Omaha, NE 68102.

MC 123885 (Sub-30TA), filed April 25, 1979. Applicant: C & R TRANSFER CO., P.O. Box 1010, Rapid City, SD 57709. Representative: Floyd E. Archer, P.O. Box 1794, Sioux Falls, SD 57101. *Machinery, and commodities which by reason of their size or weight require the use of special equipment or special handling*, from Sioux Falls, SD, to Denver and Colorado Springs, CO, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Kolman Division Athey Products Corp., P.O. Box 806, Sioux Falls, SD 57101. Send protests to: J. L. Hammond, DS, ICC, Room 455, Federal Bldg., Pierre, SD 57501.

MC 124174 (Sub-146TA), filed April 5, 1979. Applicant: MOMSEN TRUCKING CO., 13811 L St., Omaha, NE 68137. Representative: Karl E. Momsen (Same address as applicant). *Tile, facing or flooring concrete, or terrazzo tile*, from Laredo, TX to Mishawaka, IN; W. Mifflin, PA; Port Richey, Miami, and Leesburg, Fl; Minot, ND; Sioux City, IA; Denver and Colorado Springs, CO; Huntington, WV; and Fredericksburg, VA, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): (1) Royce E. Manning, Boiardi Products Corp., 1525 Fairfield Ave., Cleveland, OH 44113; (2) David Morris, Rheinschmidt Contracting Co., 1100 Agency St., Burlington, IA 52601. Send protests to: Carroll Russell, ICC, Suite 620, 110 No. 14th St., Omaha, NE 68102.

MC 124174 (Sub-147TA), filed April 18, 1979. Applicant: MOMSEN TRUCKING CO., 13811 L St., Omaha, NE 68137. Representative: Karl E. Momsen (Same address as applicant). *Iron and steel paving joints for roadway construction purposes*, from Maquoketa, to points, in KY, OH, NC, WV, IA, IL, MO, MD, WI, IN, TX, and MI, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Wady Industries, 510 E. Grove, Maquoketa, IA 52060. Send protests to: Carroll Russell, ICC, Suite 620, 110 No. 14th St., Omaha, NE 68102.

MC 124554 (Sub-34TA), filed April 4, 1979. Applicant: LANG CARTAGE CORP., 1308 S. West Ave., Waukesha, WI 53187. Representative: Richard Alexander, 710 N. Plankinton Ave., Milwaukee, WI 53203. Contract carrier; irregular routes; *Merchandise, equipment and supplies used or distributed by manufacturers of household products*, from LaCrosse, WI to points in Aitkin, Benton, Big Stone, Carlton, Chippewa, Chisago, Crow Wing, Douglas, Hennepin, Isanti, Kanabec, Lac Qui Parle, Lincoln, Lyon, Mille Lacs, Morrison, Murray, Nobles, Pine, Pipestone, Ramsey, Rock, Sherburne, St. Louis, Stevens, Swift, Todd, Washington, and Yellow Medicine Counties, MN, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Fuller Brush Co., P.O. Box 729, Great Bend, KS 67503. Send protests to: Gail Daugherty, Transportation Asst., Interstate Commerce Commission, Bureau of Operations, U.S. Federal Building and Courthouse, 517 East Wisconsin Avenue, Room 619, Milwaukee, Wisconsin 53202.

MC 124554 (Sub-35TA), filed April 26, 1979. Applicant: LANG CARTAGE CORP., P.O. Box 1465, Waukesha, WI 53187. Representative: Richard Alexander, 710 N. Plankinton Ave., Milwaukee, WI 53203. Contract carrier; irregular routes; *Paper and paper products* from facilities of Bemiss-Jason Corp. at Chicago, IL to points in WI, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Bemiss-Jason Corp., 1100 W. Cermak Rd., Chicago, IL 60608. Send protests to: Gail Daugherty, Transportation Asst., Interstate Commerce Commission, 517 East Wisconsin Avenue, Room 619, Milwaukee, Wisconsin 53202.

MC 125335 (Sub-59TA), filed April 23, 1979. Applicant: GOODWAY TRANSPORT, INC., P.O. Box 2283, York, PA 17405. Representative: Gailyn L. Larsen, P.O. Box 82816, Lincoln, NE 68501. *Such merchandise as is dealt in by wholesale and retail paint stores and supply houses*, from Chicago, IL, to points in KS, FL, MO, IA, MN, NE, ND and SD, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Standard T Chemical Co., Inc., 10th & Washington, Chicago Heights, IL 60411. Send protests to: Interstate Commerce Commission, 600 Arch Street, Room 3238, Philadelphia, PA 19106.

MC 126514 (Sub-53TA), filed April 4, 1979. Applicant: SCHAEFFER TRUCKING, INC., 5200 W. Bethany Home Rd., Glendale, AZ 85301. Representative: Leonard R. Kofkin, 39 S. LaSalle St., Chicago, IL 60603. *Photographic apparatus, equipment, material, supplies and products used for photographic application, manufacturing or processing (except commodities in bulk)*, from Rochester, NY to San Ramon, Whittier and Hollywood, CA and Dallas, TX, (2) from Windsor, CO to San Ramon and Whittier, CA, and (3) between Windsor, CO and Rochester, NY, restricted to the transportation of shipments originating at and destined to the facilities of Eastman Kodak Company at the origins and destinations named above, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper: Eastman Kodak Company, 2400 Mt. Read Blvd., Rochester, NY 14650. Send protests to: Ronald R. Mau, District Supervisor, 2020 Federal Bldg., 230 N. 1st Ave., Phoenix, AZ 85025.

MC 124775 (Sub-11TA), filed April 3, 1979. Applicant: HRIBAR TRUCKING, INC., 1521 Waukesha Rd., Caledonia, WI 53108. Representative: Leo Hribar, same address as applicant. *Crushed stone, in bulk, in dump vehicles*, from 3M Co., Wausau, WI to Chicago, Chicago Heights, and Waukegan, IL and Whiting, IN, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Minnesota Mining & Mfg. Co., 3M Center, St. Paul, MN 55101. Send protests to: Gail Daugherty, Transportation Asst., Interstate Commerce Commission, Bureau of Operations, U.S. Federal Building & Courthouse, 517 East Wisconsin Avenue, Room 619, Milwaukee, WI 53202.

MC 126305 (Sub-117TA), filed April 24, 1979. Applicant: BOYD BROTHERS TRANSPORTATION COMPANY, INC., RFD 1, Box 18, Clayton, AL 36016. Representative: George A. Olsen, P.O. Box 357, Gladstone, NJ 07934. *Carpenters molding, door frames and/or inside trim work with shellac in addition to prime*. Between the facilities of Hampton Hardwood Corporation, at or near Hampton and Newport News, VA, on the one hand, and, on the other, points in and east of MN, IA, NE, OK and TX, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Hampton Hardwood Corportation, 2100 56th Street, Hampton, VA; Hampton Hardwood Corporation, P.O. Box 5109, Parkview Station, Newport News, VA 23605. Send protests to: Mabel E. Holston, T/A, ICC, Room 1616, 2121 Building, Birmingham, AL 35203.

MC 126514 (Sub-54TA), filed April 4, 1979. Applicant: SCHAEFFER

TRUCKING, INC., 5200 W. Bethany Home Rd., Glendale, AZ 85301. Representative: Leonard R. Kofkin, 39 S. LaSalle St., Chicago, IL 60603. *Foodstuffs (except frozen foodstuffs and commodities in bulk) and materials, supplies and equipment used in the manufacture and sale thereof (except commodities in bulk),* between the facilities of Ragu Foods, Inc. at Merced, CA and Rochester, NY, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Ragu Foods, Inc., 33 Benedict Place, Greenwich CT 06830. Send protests to: Ronald R. Mau, District Supervisor, 2020 Federal Bldg., 230 N. 1st Ave., Phoenix, AZ 85025.

MC 126305 (Sub-118TA), filed April 12, 1979. Applicant: BOYD BROTHERS TRANSPORTATION CO., INC., RFD 1, Box 18, Clayton, AL 36016. Representative: George A. Olsen, P.O. Box 357, Gladstone, NJ 07934. *Lumber and wood products,* surfaced but not primed or finished, from Warren, AR, and El Paso, TX, to points in VA, for 180 days. Supporting shipper(s): Rawles, Aden Lumber Corporation, River Street, P.O. Box 269, Petersburg, VA 23803. Send protests to: Mabel E. Holston, T/A, ICC, Room 1616, 2121 Building, Birmingham, AL 35203.

MC 128205 (Sub-74TA), filed March 23, 1979. Applicant: BULKMATIC TRANSPORT COMPANY, 12000 South Doty Avenue, Chicago, IL 60628. Representative: Arnold L. Burke, 180 North LaSalle Street, Chicago, IL 60601. *Cereal food products in bulk:* from Battle Creek, MI to Delavan, MI, for 180 days. An underlying ETA was granted for 90 days authority. Supporting shipper(s): Peterson Company, P.O. Box 60, Battle Creek, MI 49016. Send protests to: Annie Booker, TA, Interstate Commerce Commission, 219 South Dearborn Street, Room 1386, Chicago, IL 60604.

MC 126514 (Sub-55TA), filed April 9, 1979. Applicant: SCHAEFFER TRUCKING, INC., 5200 W. Bethany Home Rd., Glendale AZ 85301. Representative: Leonard R. Kofkin, 39 S. LaSalle St., Chicago, IL 60603. *(1) Such merchandise, materials, equipment and supplies as are used, manufactured or dealt in by manufacturers and distributors of paper and film products and (2) photographic materials and reproduction and duplicating products and supplies,* from S. Hadley and Holyoke, MA to Chicago, IL, Oklahoma City and Tulsa, OK and points in CA, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): James River Graphics, Inc., 28 Gaylord St., So. Hadley, MA 01075. Send protests to: Ronald R. Mau, District Supervisor, 2020 Federal Bldg., 230 N. 1st Ave. Phoenix, AZ 85025.

MC 126514 (Sub-56TA), filed April 13, 1979. Applicant: SCHAEFFER TRUCKING, INC., 5200 W. Bethany Home Rd., Glendale, AZ 85301. Representative: Leonard R. Kofkin, 39 S. LaSalle St., Chicago, IL 60603. *Plastic liquid, plastic film and sheeting, chemicals, cleaning and scouring compounds, defoaming compounds, laminating machinery or parts, ink, solvents, pallets, and empty containers,* between the facilities of Thiokol/ Dynachem Corp. in Orange County, CA on the one hand, and, on the other, Elmhurst, IL, Indianapolis and Terre Haute, IN, Woburn and South Hadley Falls, MA, Kearny, NJ, Farmingdale, NY, Matthews and Charlotte, NC, and Herndon, VA, restricted against the transportation of commodities in bulk, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Thiokol/Dynachem Corp. P.O. Box 12047, Santa Ana, CA 92711. Send protests to: Ronald R. Mau, District Supervisor, 2020 Federal Bldg., 230 N. 1st Ave., Phoenix, AZ 85025.

MC 126844 (Sub-82TA), filed April 2, 1979. Applicant: R.D.S. TRUCKING CO., INC., 1713 North Main Road, Vineland, NJ 08360. Representative: Kenneth F. Dudley, 611 Church Street, P.O. Box 279, Ottumwa, Iowa 52501. *Physical fitness apparatus,* (1) from Pennsauken, NJ to points in AR, CO, GA, IL, IN, IA, KS, KY, LA, MI, MN, MS, MO, NY, NC, OH, OK, PA, SC, TN, VA, WV, and WI, and (2) from Seabrook, NJ to Edgewater Park and Pennsauken, NJ, for 180 days. Supporting shipper(s): General Home Products Corp., Suckle & National Highway, Pennsauken, NJ 08110. Send protests to: District Supervisor, ICC, 428 East State Street, Room 204, Trenton, NJ 08608.

MC 127524 (Sub-18TA), filed April 2, 1979. Applicant: QUADREL BROS. TRUCKING COMPANY, INC., 1603 Hart Street, Rahway, NJ 07065. Representative: John L Alfano, Esq. (Alfano & Aflano, P.C.), 550 Mamaroneck Avenue, Harrison, NY 10528. *Mineral oil, in bulk,* from Bayonne and Bayway, NJ to Baltimore, MD, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Johnson & Johnson Baby Products, 220 Centennial Avenue, Piscataway, NJ 08854. Send protests to: Robert E. Johnston, D/S, ICC, 9 Clinton Street, Room 618, Newark, NJ 07102.

MC 127524 (Sub-1TA), filed April 2, 1979. Applicant: QUADREL BROS. TRUCKING COMPANY, INC., 1603 Hart Street, Rahway, NJ 07065. Representative: John L Alfano, Esq. (Alfano & Aflano, P.C.), 550 Mamaroneck Avenue, Harrison, NY 10528. *Chemicals, in bulk in marinized tankwagons,* from Newark, NJ to Baltimore, MD for 180 days. Restricted to shipments having a prior or subsequent movement by water. An underlying ETA seeks 90 days authority. Supporting shipper(s): Celanese Chemical, Incorporated, 1250 West Mockingbird Lane, Dallas, TX 75247. Send protests to: Robert E. Johnston, D/S, ICC, 9 Clinton Street, Room 618, Newark, NJ 07102.

MC 127524 (Sub-20TA), filed April 9, 1979. Applicant: QUADREL BROS. TRUCKING COMPANY, INC., 1603 Hart Street, Rahway, NJ 07065. Representative: John L. Alfano and Roy A. Jacobs, Esqs., 550 Mamaroneck Avenue, Harrison, NY 10528. Plastic pellets, in bulk, in tank vehicles. From Edison, NJ to Avon and Cortland, NY, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Allied Chemical Corporation, P.O. Box 1087R, Morristown, NJ 07960. Send protests to: Robert E. Johnston, DS, ICC, 9 Clinton Street, Room 618, Newark, NJ 07102.

MC 127974 (Sub-16TA), filed April 17, 1979. Applicant: P. LIEDTKA TRUCKING, INC., 110 Patterson Avenue, Trenton, N.J. 08610. Representative: Alan Kahn, Esquire, 1920 Two Penn Center Plaza, Philadelphia, Pa. 19102. *Iron and steel articles,* from the facilities of United States Steel Corporation in Allegheny and Westmoreland Counties, PA to points in NJ, for 150 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): United States Steel Corporation, 600 Grant Street, Pittsburgh, Pa. 15230. Send protests to: District Supervisor, ICC, 428 East State Street, Room 204, Trenton, N.J. 08608.

MC 133315 (Sub-4TA), filed April 25, 1979. Applicant: ASBURY SYSTEM, 222 East 38th Street, Vernon, CA 90058. Representative: Howard D. Clark, same address as applicant. *Petroleum products, in bulk, in tank vehicles,* from South Gate and Carson, CA to Phoenix, AZ, for 180 days. An underlying ETA seeks up to 90 days operating authority. Supporting shipper(s): ARCO Petroleum Products Company, A Division of Atlantic Richfield Company, 505 So. Flower Street, Los Angeles, CA 90071. Send protests to: Irene Carlos, Transportation Assistant, Interstate Commerce Commission, P.O. Box 1551, Los Angeles, CA 90053.

MC 133485 (Sub-28TA), filed April 6, 1979. Applicant: INTERNATIONAL DETECTIVE SERVICE, INC., 1828 Westminister Street, Providence, RI 02909. Representative: Morris J. Levin, 1050 Seventeenth Street, N.W., Washington, DC 20036. *Cobalt metal, escorted by armed guards,* between New York, NY and Muskegon, MI, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Phillip Brothers, 1221 Avenue of the Americas, New York, NY 10020. Send protests to: Gerald H. Curry, District Supervisor, 24 Weybosset Street, Room 102, Providence, RI 02903.

MC 133655 (Sub-150TA), filed April 11, 1979. Applicant: TRANS-NATIONAL TRUCK, INC., P.O. Box 31300, Amarillo, TX 79120. Representative: Warren L. Troupe, 2480 E. Commercial Blvd., Fort Lauderdale, FL 33308. (1) *Paper and paper products* (except commodities in bulk); and (2) *equipment materials, and supplies* used in the manufacture and distribution of paper and paper products (except commodities in bulk) between Azusa, Monrovia, Whittier, and Cucamonga, CA; Gainesville, GA; North Brunswick, NJ; Cleveland, Cincinnati, Painesville, and Willoughby, OH; Elmhurst, IL; Philadelphia and Quakertown, PA; Charlotte and Greensboro, NC; and Schereville, IN on the one hand, and, on the other, points in the United States, for 180 days. Supporting shipper(s): Fasson Products, 316 Highway 74, South, Peachtree City, GA 30269. Send protests to: Haskell E. Ballard, Box F-13206 Federal Building, Interstate Commerce Commission—Bureau of Operations, Amarillo, TX 79101.

MC 133975 (Sub-8TA), filed April 6, 1979. Applicant: FLAMINGO TRANSPORTATION, INC., 11405 N.W. 36th Ave., Miami, FL 33167. Representative: Richard B. Austin, 5255 N.W. 87th Ave., Miami, FL 33178. *General commodities* (except articles of unusual value, classes A & B explosives, household goods as defined by the Commission, commodities in bulk, those requiring special equipment, and mobile homes) between points in Escambia, Leon, and Duval Counties, FL, on the one hand, and, on the other points in Escambia, Santa Rosa, Okaloosa, Walton, Holmes, Washington, Bay, Jackson, Calhoun, Liberty, Gulf, Gadsden, Franklin, Wakulla, Leon, Jefferson, Madison, Taylor, Hamilton, Suwannee, Lafayette, Dixie, Levy, Gilchrist, Columbia, Baker, Union, Bradford, Alachua, Putnam, Flagler, St. Johns, Clay, Duval and Nassau Counties, FL restricted to traffic having an immediately prior or subsequent handling by freignt forwarder for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Florida-Texas Freight, Inc., 11405 N.W. 36th Ave., Miami, FL 33167. Send protests to: Donna M. Jones, TA, ICC-BOp, Monterey Bldg., Suite 101, 8410 N.W. 53rd Ter., Miami, FL 33166.

MC 134405 (Sub-71TA), filed April 18, 1979. Applicant: BACON TRANSPORT COMPANY, P.O. Box 1134, Ardmore, OK 73401. Representative: Wilburn L. Williamson, Suite 615-East, The Oil Center, 2601 Northwest Expressway, Oklahoma City, OK 73112. *Anhydrous ammonia,* in bulk, in tank vehicles, from Ft. Madison, IA, to points in IL and MO, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Swift Agricultural Chemicals Corporation, 30 N. LaSalle, Chicago, IL 60602. Send protests to: District Supervisor, Interstate Commerce Commission, Room 240, Old Post Office & Court House Bldg., 215 N.W. 3rd, Oklahoma City, OK 73102.

MC 134405 (Sub-72TA), filed April 9, 1979. Applicant: BACON TRANSPORT COMPANY, P.O. Box 1134, Ardmore, OK 73401. Representative: Wilburn L. Williamson, Suite 615-East, The Oil Center, 2601 Northwest Expressway, Oklahoma City, OK 73112. *Rubber,* from the Port of Muskogee, OK, to Ardmore, OK, restricted to the transportation of traffic having a prior movement by water, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Uniroyal Corporation, Box 1867, Ardmore, OK 73401. Send protests to: District Supervisor, Interstate Commerce Commission, Room 240, Old Post Office & Court House Bldg., 215 N.W. 3rd, Oklahoma City, OK 73102.

MC 134405 (Sub-73TA), filed April 11, 1979. Applicant: BACON TRANSPORT COMPANY, P.O. Box 1134, Ardmore, Oklahoma 73401. Representative: Willburn L. Williamson, Suite 615-East, The Oil Center, 2601 Northwest Expressway, Oklahoma City, Oklahoma 73112. *Anhydrous ammmonia, in bulk, in tank vehicles* from Lake Charles, LA, to Pasadena, TX for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Fertilizer Company of Texas, Inc., P.O. Box 3444, Pasadena, Texas 77501. Send protests to: Connie Stanley, Transportation Assistant, Room 240, Old Post Office Bldg., 215 N.W. Third Street, Oklahoma City, Oklahoma 73102.

MC 135185 (Sub-39TA), filed April 25, 1979. Applicant: COLUMBINE CARRIERS, INC., P.O. Box 15246, 1720 East Garry Avenue, Santa Ana, CA 92705. Representative: Charles J. Kimball, Kimball, Williams & Wolfe, P.C., 350 Capitol Life Center, 1600 Sherman Street, Denver, CO 80203. *Contract:* irregular: *Paints, stains, varnishes and polyurethane finishings (except in bulk),* from the facilities of Sterling Drug, Inc., at or near Flora, IL, to the facilities of Lehn and Fink Products Co., a Division of Sterling Drug, Inc., at or near Belle Mead, NJ, for 180 days. Restricted to a transportation service to be performed under a continuing contract(s) with Lehn and Fink Products Co., a Division of Sterling Drug, Inc. An underlying ETA seeking up to 90 days operating authority has been filed. Supporting shipper(s): Lehn & Fink Products Co., A Division of Sterling Drug, Inc., 225 Summit Avenue, Montvale, NJ 07645. Send protests to: Irene Carlos, Transportation Assistant, Interstate Commerce Commission, P.O. Box 1551, Los Angeles, CA 90053.

MC 135185 (Sub-40TA), filed April 25, 1979. Applicant: COLUMBINE CARRIERS, INC., P.O. Box 15246, 1720 East Garry Avenue, Santa Ana, CA 92705. Representative: Charles J. Kimball, Kimball, Williams & Wolfe, P.C., 350 Capitol Life Center, 1600 Sherman Street, Denver, CO 80203. *Contract:* irregular: *(1) Disinfectants and deodorant compounds (except in bulk),* from the facilities of Production Control, Inc., at or near Chicago, IL and the facilities of Cadillac Packaging at or near North Chicago, IL, to points in WA, CA, TX, NJ, FL, and OH; *(2) Cannisters,* from the facilities of Milton Can at or near Cranbury, NJ, to the facilities of Production Control, Inc., at or near Chicago, IL and the facilities of Cadillac Packaging at or near North Chicago, IL; and *(3) Sodium sulfate, in bags,* (a) from the facilities of International Salt at or near Lowland, TN, and (b) from the facilities of Prior Chemical, at or near Kings Mountain and Bessemer City, NC, to the facilities of Production Control, Inc., at or near Chicago, IL and the facilities of Cadillac Packaging at or near North Chicago, IL, restricted in parts (1), (2), and (3) to a transportation service to be performed under a continuing contract or contracts with Lehn & Fink Products Co., a Division of Sterling Drug, Inc., for 180 days. An underlying ETA seeks up to 90 days operating authority. Supporting shipper(s): Lehn & Fink Products Co., A Division of Sterling Drug, Inc., 225 Summit Avenue, Montvale, NJ 07645. Send protests to: Irene Carlos, Transportation Assistant, Interstate Commerce Commission, P.O. Box 1551, Los Angeles, CA 90053.

MC 135524 (Sub-24TA), filed April 5, 1979. Applicant: G. F. TRUCKING COMPANY, 1028 West Rayen Avenue, Youngstown, OH 44501. Representative: George Fedorisin, 914 Salt Springs Road, Youngstown, OH 44509. *Lumber, lumber mill products, and wood products,* from the facilities of Potlatch Corporation located at or near Coeur d' Alene, St. Maries, Potlatch, Lewiston, Kamiah, Spalding, Jaype (near Pierce), Santa and Post Falls, ID, to all points in IN, MI, MO, and OH, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Potlatch Corporation, P.O. Box 1016, Lewiston, ID 83501. Send protests to: Mary Wehner, D/S, ICC, 731 Federal Bldg., Cleveland, OH 44199.

MC 135684 (Sub-92TA), filed April 17, 1979. Applicant: BASS TRANSPORTATION CO., INC., P.O. Box 391, Old Croton Road, Flemington, N.J. 08822 Representative: Ronald L. Knorowski (same address as applicant). *Starch and chemicals* (except in bulk), from the facilities of National Starch and Chemical Corp., at or near Indianapolis, IN to points in CT, MA, ME, MD, NJ, NY, PA, RI and VA, for 180 days. An underlying ETA seeks 90 days authority Supporting shipper(s): National Starch & Chemical Corp., P.O. Box 6500, Bridgewater, N.J. 08807. Send protests to: District Supervisor, ICC, 428 East State Street, Room 204, Trenton, N.J. 08608.

MC 135874 (Sub-165TA), filed April 4, 1979. Applicant: LTL PERISHABLES, INC., 550 East 5th Street South, South St. Paul, MN 55075. Representative: Paul Nelson (same address as applicant). *Fertilizer, aluminum ladders and oak barrels (all except in bulk)* from Milwaukee, WI, Warsaw, IN, and Louisville, KY to the facilities of Warner Hardware in the Minneapolis, MN Commercial Zone, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Warners, Marketing Manager, 2745 South Lexington Avenue, St. Paul, MN 55121. Send protests to: Delores A. Poe, TA ICC, 414 Federal Building & U.S. Court House, 110 South 4th Street, Minneapolis, MN 55401.

MC 135874 (Sub-166TA), filed April 4, 1979. Applicant: LTL PERISHABLES, INC., 550 East 5th Street South, South St. Paul, MN 55075. Representative: Paul Nelson (same address as applicant). *Frozen foods, (except commodites in bulk),* from the facilities of the Pillsbury Company in the Minneapolis, MN Commercial Zone to points in IN, OH, MI, IL, MO, KY, PA and NY, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): The Pillsbury Co., Frozen Foods Division, Traffic Manager, 608 2nd Avenue South, Minneapolis, MN 55402. Send protests to: Delores A. Poe, TA ICC, 414 Federal Building & U.S. Court House, 110 South 4th Street, Minneapolis, MN 55401.

MC 135874 (Sub-167TA), filed April 4, 1979. Applicant: LTL PERISHABLES, INC., 550 East 5th Street South, South St. Paul, MN 55075. Representative: Paul Nelson (same address as applicant). *Kitchen cabinets, bathroom vanities, dehumidifiers and microwave ovens (all except in bulk)* from Sellersburg, IN, Albion, MI and Little Fern, NJ to the facilities of Menard's, Inc. at Cedar Rapids, IA, Rochester, Belgrade and St. Cloud, MN and the Minneapolis, MN Commercial Zone, and Eau Claire, LaCrosse and Wausaw, WI, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Menard's, Inc., Merchandise Manager, Route 2, Eau Claire, WI 54701. Send protests to: Delores A. Poe, TA ICC, 414 Federal Building and U.S. Court House, 110 South 4th Street, Minneapolis, MN 55401.

MC 135895 (Sub-37TA), filed February 22, 1979. Applicant: B & R DRAYAGE, INC., P.O. Box 8534, Battlefield Station, Jackson, MS 39204. Representative: Douglas C. Wynn, P.O. Box 1295, Greenvile, MS 38701. *Paper and paper products and equipment, materials and supplies* used in the conversion, manufacture and distribution of paper and paper products (except commodities in bulk) between the facilities of Olinkraft, Inc. at or near Monroe and West Monroe, LA, on the one hand, and, on the other, points in AL, AR, GA, FL, MS, TN, and TX, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Olinkraft, Inc., P.O. Box 488, West Monroe, LA 71291. Send protests to: Alan Tarrant, D/S, ICC, Rm. 212, 145 E. Amite Bldg., Jackson, MS 39201.

MC 135895 (Sub-38TA), filed February 23, 1979. Applicant: B & R DRAYAGE, INC., P.O. Box 8534, Battlefield Station, Jackson, MS 39204. Representative: Douglas C. Wynn, P.O. Box 1295, Greenville, MS 38701. *Plastic granules, pellets and powder, and ethanolmines,* in containers (except commodities in bulk and commodities requiring special equipment) from the facilities of Dow Chemical Corp. at or near Baton Rouge and Plaquemine, LA to points in AL, AR, FL, GA, LA, MS, NC, OK, SC, TN and TX, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Dow Chemical Corp., P.O. Box 150, Plaquemine, LA 70764. Send protests to: Alan Tarrant, D/S, ICC, Rm. 212, 145 E. Amite Bldg., Jackson, MS 39201.

MC 135924 (Sub-8TA), filed April 24, 1979. Applicant: SIMONS TRUCKING CO., INC., 3851 River Road, Grand Rapids, MN 55744. Representative: Samuel Rubenstein/David Rubenstein, 301 North Fifth Street, Minneapolis, MN 55403. *Composition board* from the facilities of Abitibi Corporation, Chicago, IL to points in MN, ND, SD, IA and NE, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Abitibi Corporation, 3250 West Big Beaver Road, Troy, MI 48084. Send protests to: Delores A. Poe, TA, ICC, 414 Federal Building & U.S. Court House, 110 South 4th Street, Minneapolis, MN 55401.

MC 136315 (Sub-70TA), filed April 24, 1979. Applicant: OLEN BURRAGE TRUCKING, INC., Rt. 9, Box 22–A, Philadelphia, MS 39350. Representative: Fred W. Johnson, Jr., 1500 Deposit Guaranty Plaza, Jackson, MS 39205. *Freight and passenger elevators, parts and attachments therefor* (1) between the facilities of Dover Corp./Elevator Div. DeSoto County, MS, on the one hand, and, on the other, the facilities of Dover Corp./Elevator Div., Hardeman County, TN; (2) from the facilities of Dover Corp./Elevator Div., DeSoto County, MS, and Hardeman County, TN to points in IL, IN, OH, MI, WI, IA, and MN, and (3) *materials, equipment and supplies* in the reverse direction in (2) above, (Restricted against the transportation of commodities in bulk and commodities which because of size and weight require the use of special equipment) for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Dover Corp Elevator Div., P.O. Box 2177, Memphis, TN 38101. Send protests to: Alan Tarrant, D/S, ICC, Rm. 212, 145 E. Amite Bldg., Jackson, MS 39201.

MC 136315 (Sub-71TA), filed April 24, 1979. Applicant: OLEN BURRAGE TRUCKING, INC., Rt. 9, Box 22–A, Philadelphia, MS 39350. Representative: Fred W. Johnson, Jr., P.O. Box 22628, Jackson, MS 39205. *Iron and steel articles* from the facilities of Jones and Laughlin Steel Corporation located in Putnam County, Illinois to points in AR, MS, OK, TN, Kansas City, KS and Kansas City, MO, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Jones and Laughlin Steel Corp., Hennepin, IL 61527. Send protests to: Alan Tarrant, D/S, ICC, Rm. 212, 145 E. Amite Bldg., Jackson, MS 39201.

MC 136315 (Sub-72TA), filed April 3, 1979. Applicant: OLEN BURRAGE TRUCKING, INC., Rt. 9, Box 22–A, Philadelphia, MS 39350. Representative: Fred W. Johnson, Jr., 1500 Deposit Guaranty Plaza, P.O. Box 22628, Jackson, MS 39205. *Adhesives*, except in bulk, from facilities of General Adhesives & Chemical Co., Davidson County, TN to points in AL, AR, GA, LA, MS, OK, and TX, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): General Adhesives & Chemical Co., 6100 Centennial Blvd., Nashville, TN 37202. Send protests to: Alan Tarrant, D/S, ICC, Rm. 212, 145 E. Amite Bldg., Jackson, MS 39201.

MC 136384 (Sub-16TA), filed April 6, 1979. Applicant: PALMER MOTOR EXPRESS, INC., P.O. Box 103, Savannah, GA 31402. Representative: W. W. Palmer, Jr. (same as applicant). *Foodstuffs and such other commodities as are dealt in by wholesale and retail chain and grocery houses, and in connection therewith, equipment, materials, and supplies used in the conduct of such business, restricted against the transportation of commodities in bulk and against the transportation of shipments in vehicles equipped with mechanical refrigeration* between the facilities of Savannah Foods and Industries, Inc., and Transales Corporation, in Chatham County, GA, on the one hand, and, on the other, points in FL and GA for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Transales Corporation, P.O. Box 9177, Savannah, GA 31412. Send protests to: G. H. Fauss, Jr., DS, ICC, Box 35008, 400 West Bay Street, Jacksonville, FL.

MC 136484 (Sub-17TA), filed April 3, 1979. Applicant: PALMER MOTOR EXPRESS, INC., P.O. Box 103, Savannah, GA 31402. Representative: W. W. Palmer, Jr. (same as applicant). 111. (a) Regular routes: *General commodities*, (except those of unusual value, classes A and B explosives, household goods as defined by the Commission, commodities in bulk, and commodities requiring special equipment), 1. Between Vidalia and Atlanta, Georgia; From Vidalia over U.S. Highway 280 to Mc Rae, thence over U.S. Highway 280 to its intersection with U.S. Highway 441, thence over U.S. Highway 441 to Madison, Georgia, thence over U.S. Highway 278 to Atlanta, Georgia, and return over the same route serving all intermediate points and the off route points of Social Circle, Porterdale, and Milstead. 2. Between Athens and Atlanta, Georgia; From Athens over U.S. Highway 29 to Atlanta and return over the same route serving all intermediate points, and the off route point of Watkinsville, Ga. 3. Between Winder and Athens, Georgia; from Winder over Georgia Highway 11 to Jefferson, thence over Georgia Highway 15 to Commerce, thence over U.S. Highway 441 to Athens, Georgia and return serving all intermediate points. 4. Between Dublin and Atlanta, Georgia; serving no intermediate points and for operating convenience only. From Dublin over Georgia Highway 257 to its intersection with Interstate 16, thence over Interstate 16 to its intersection with Interstate 75, at or near Macon, Ga., thence over Interstate 75 to Atlanta, Georgia. 5. Between Madison and Athens, Georgia, serving no intermediate points and for operating convenience only. From Madison over U.S. Highway 441 to Athens, Georgia. For 180 days. Supporting shipper(s): There are 50 supporting shippers. Their statements may be examined at the office listed below and Headquarters. Send protests to: G. H. Fauss, Jr., DS, ICC, Box 35008, 400 West Bay Street, Jacksonville, FL 32202.

MC 136545 (Sub-20TA), filed April 17, 1979. Applicant: NUSSBERGER BROS. TRUCKING CO., INC., 929 Railroad St., Prentice, WI 54556. Representative: Richard Westley, 4506 Regent St., Suite 100, Madison, WI 53705. *Flatbed and dropdeck trailers designed to be drawn by semi-tractors in initial movements* from Birmingham, AL; Lufkin, TX and Elizabeth, WV to the facilities of Dalke Trailer Sales at or near New Brighton, MN, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Vulcan Trailer Mfg. Co., 1321 Third St. Ensley, Birmingham, AL 35214, and Dalke Trailer Sales, 1155 Old Hwy. 8, New Brighton, MN 55112. Send protests to: Gail Daugherty, Transportation Asst., Interstate Commerce Commission, 517 E. Wisconsin Ave., Rm. 619, Milwaukee, WI 53202.

MC 136545 (Sub-21TA), filed April 2, 1979. Applicant: NUSSBERGER BROS. TRUCKING CO., INC., 929 Railroad St., Prentice, WI 54556. Representative: Richard Westley, 4506 Regent St., Suite 100, Madison, WI 53705. *Structural steel tubing* from the facilities of Welded Tube Co. of America in Chicago, IL to points in the Minneapolis-St. Paul, MN Commercial Zone, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Welded Tube Co. of America, 1855 E. 122nd St., Chicago, IL 60633. Send protests to: Gail Daugherty, Transportation Asst., Interstate Commerce Commission, Bureau of Operations, U.S. Federal Building and Courthouse, 517 East Wisconsin Avenue, Room 619, Milwaukee, Wisconsin 53202.

MC 136545 (Sub-22TA), filed April 13, 1979. Applicant: NUSSBERGER BROS. TRUCKING CO., INC., 929 Railroad St., Prentice, WI 54556. Representative: Richard Westley, 4506 Regent St., Suite 100, Madison, WI 53705. *Materials, equipment and supplies used in the manufacture and distribution of in-plant handling and processing equipment* from points in IL, IN, MI, MN, & OH to the facilities of Marquip, Inc. located at or near Phillips, WI, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Marquip, Inc., N. Airport Rd., Phillips, WI 54555. Send protests to: Gail Daugherty, Transportation Asst., ICC, Bureau of Operations, U.S. Federal Bldg & Courthouse, 517 East Wisconsin Ave., Rm 619, Milwaukee, WI 53202.

MC 136605 (Sub-102TA), filed April 24, 1979. Applicant: DAVIS BROS. DIST., INC., P.O. Box 8058, Missoula, MT 59807. Representative: Allen P. Felton (same address as Applicant). *Iron, steel and aluminum articles* from the facilities of A. M. Castle & Co. located at or near Franklin Park, IL to the facilities of A. M. Castle & Co. located at or near Los Angeles, San Francisco, and Fresno, CA and Salt Lake City, UT, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): A. M. Castle & Co., 3400 N. Wolf Rd., Franklin Park, IL 60131. Send protests to: Paul J. Labane, DS, ICC, 2602 First Avenue North, Billings, MT 59101.

MC 136605 (Sub-104TA), filed April 18, 1979. Applicant: DAVIS BROS. DIST., INC., P.O. Box 8058, Missoula, MT 59807. Representative: Allen P. Felton (same address as Applicant). *Iron and steel articles* from the facilities of Jones and Laughlin Steel Corporation located in Hammond, IN and in the Chicago Commercial Zone in IN and IL to points in the States of WA, OR and CA, restricted to traffic originating at the named origin points, for 180 days. Supporting shipper(s): Jones and Laughlin Steel Corporation, 141 West 141st Street, Hammond, IN 46325. Send protests to: Paul J. Labane, DS, ICC, 2602 First Avenue North, Billings, MT 59101.

MC 138104 (Sub-78TA), filed April 16, 1979. Applicant: MOORE TRANSPORTATION CO., INC., 3509 N. Grove Street, Fort Worth, TX 76106. Representative: Bernard H. English, 6270 Firth Road, Fort Worth, TX 76116. *Clay fines*, in bulk, in tank vehicles, from points in Saline and Pulaski Counties, AR to points in Ellis County, TX, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Texas Industries, P.O. Box 400, Arlington, TX 76011. Send protests to: James H. Berry, ROD, ICC, Room 9A27, Federal Bldg., 819 Taylor St., Fort Worth, TX 76102.

MC 138144 (Sub-50TA), filed April 5, 1979. Applicant: FRED OLSON CO., INC., 6022 West State Street, Milwaukee, WI 53213. Representative: William D. Brejcha, 10 South LaSalle Street, Chicago, IL 60603. *Plastic pipe and accessories used in the installation thereof*, from the facilities of Johns-Manville Sales Corporation, Wilton, IA to points in IL, IN, MI, MO and WI, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Johns-Manville Sales Corporation, 2222 Kensington Court, Oak Brook, IL 60521. Send protests to: Gail Daugherty, Transportation Asst., Interstate Commerce Commission, Bureau of Operations, U.S. Federal Building & Courthouse, 517 East Wisconsin Avenue, Room 619, Milwaukee, Wisconsin 53202.

MC 138465 (Sub-6TA), filed March 29, 1979. Applicant: PHIL TOWNSEND, JR., Route 1, Box 19, Live Oak, FL 33830. Representative: Dan R. Schwartz, 1729 Gulf Life Tower, Jacksonville, FL 32207. (1) *Agricultural limestone*, in bulk, in dump vehicles, from points in Citrus and Taylor Counties, FL to points in GA on and south of U.S. Highway 280; (2) *Wet Gypsum*, in bulk, in dump vehicles, from points in Hamilton County, FL to points in GA on and south of U.S. Highway 280 and in Coffee, Covington, Dale, Geneva, Henry, and Houston Counties, AL; (3) *Superphosphate, including triple superphosphate, ammoniated and potassiated phosphate other than feed grade, but including diammonium phosphate, in bulk, in dump-type vehicles*, from points in Hamilton, Hillsborough, Manatee, and Polk Counties, FL to points in GA on and south of U.S. Highway 280 and in Coffee, Covington, Dale, Geneva, Henry, and Houston Counties, AL for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): There are 8 shippers. Their statments may be examined at the office listed below and Headquarters. Send protests to: G. H. Fauss, Jr., DS, ICC, Box 35008, 400 West Bay Street, Jacksonville, FL #2202.

MC 139274 (Sub-6TA), filed April 2, 1979. Applicant: THE DANIEL COMPANY OF SPRINGFIELD, 419 E. Kearney, Springfield, Missouri 65803. Representative: Turner White, 910 Plaza Towers, Springfield, Missouri 65804. Contract, irregular. *Plastic jugs*, from Centralia, IL to Fresno, CA, for 180 days. An underlying ETA seeks 90 days authority. Restriction: Service to be performed under a continuing contract or contracts with the R. T. French Company of Rochester, NY. Supporting shipper(s): R. T. French Company, 4455 East Mustard Way, Rochester, New York. Send protests to: John V. Barry, District Supervisor, Interstate Commerce Commission, 600 Federal Building, 911 Walnut Street, Kansas City, Missouri 64106.

MC 139395 (Sub-4TA), filed April 6, 1979. Applicant: BULK TRANSIT CORPORATION, 2040 North Wilson Road, Columbus, Ohio 43228. Representative: Andrew Jay Burkholder, 275 East State St., Columbus, Ohio 43215. *Lime* in bulk in tank vehicles from Knox County, TN to Carrollton, KY from Knox County, TN to points in OH south of U.S. Highway 30, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Williams Lime Mfg., Inc., Knoxville, TN. Send protests to: ICC, WM Jr. Green, Jr. Federal Bldg., 600 Arch Street, Philadelphia, PA 19106.

MC 139485 (Sub-17TA), filed April 12, 1979. Applicant: TRANS CONTINENTAL CARRIERS, 169 East Liberty Avenue, Anaheim, CA 92803. Representative: David P. Christianson, Kanpp, Grossman & Marsh, 707 Wilshire Blvd., Suite 1800, Los Angeles, CA 90017. *Contract:* irregular: *(1) Foods, foodstuffs, food treating compounds; chemicals and additives (except in bulk); and advertising paraphernalia; materials, equipment, and supplies used in the manufacture, preparation, sale and distribution of commodities listed above; and (2) Commodities, the transportation of which is exempt from regulation under provisions of Section 10526 (a), (b), and (c) of the Interstate Commerce Act, in mixed loads with the commodities described in (1) above*, between the facilities used by McCormick & Company, Inc., and its subsidiaries in the United States, on the one hand, and, on the other, points in the United States, for 180 days. An underlying ETA seeks up to 90 days operating authority. Supporting shipper(s): McCormick & Company, Inc., 414 Light Street, Baltimore, MD 21202. Send protests to: Irene Carlos, Transportation Assistant, Interstate Commerce Commission, P.O. Box 1551, Los Angeles, California 90053.

MC 140024 (Sub-147TA), filed April 5, 1979. Applicant: J. B. MONTGOMERY, INC., 5565 East 52nd Ave., Commerce City, CO 80022. Representative: Don Bryce (same as applicant). *Iron and Steel articles* from Farrell, PA to Clinton, Ottumwa, Des Moines and Dubuque, IA; St. Louis and St. Joseph, MO; DeWitt, NE; Paola, KS; Denver, Commerce City, Longmont, Simla and Loveland, CO for 180 days. Underlying ETA filed seeking 90 days authority. Supporting shipper: Sharon Steel Corp. P.O. Box 591, Sharon, PA 16146. Send protests to: D/S Roger L. Buchanan, ICC, 721 19th St., 492 U.S. Customs House, Denver, CO 80202.

MC 140024 (Sub-148TA), filed April 12, 1979. Applicant: J. B. MONTGOMERY, INC., 5565 East 52nd Ave., Commerce City, CO 80022. Representative: Don L. Bryce (same as applicant). *Foodstuffs (except in bulk)*, in mechanically refrigerated vehicles from Brockport and Holley, NY to points in IL, IN, IA, MI, OH, and PA, for 180 days. Underlying ETA seeks 90 days authority. Supporting shipper: Curtice Burns, Inc., Lent Avenue, LeRoy, NY 14482. Send protests to: Roger L. Buchanan, ICC, 492 U.S. Customs House 721 19th St., Denver, CO 80202.

MC 141205 (Sub-14TA), filed April 27, 1979. Applicant: HUSKY OIL TRANSPORTATION COMPANY, 600 South Cherry Street, Denver, CO 80222. Representative: F. Robert Reeder and James M. Elegante, P.O. Box 11898, Salt Lake City, UT 84147. Contract—irregular route. *Crude oil, scrubber oil and condensate*, from Richland, Roosevelt, McCone, Prairie and Wibaux Counties, MT to Reserve Station of Portal Pipeline near Plentywood, MT, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Husky Oil Company, 600 South Cherry Street, Denver, CO 80222. Send protests to: District Supervisor, Herbert C. Ruoff, 492 U.S. Customs House, 721 19th Street, Denver, CO 80202.

MC 140484 (Sub-41 TA), filed April 6, 1979. Applicant: LESTER COGGINS TRUCKING, INC., 2671 E. Edison Ave., P.O. Box 69, Fort Myers, FL 33902. Representative: Chester A. Zyblut, 366 Executive Bldg., 1030 15th St. NW, Washington, D.C. 20005. *Transformers and parts and accessories* (except those commodities which because of size or weight require the use of special equipment) (a) from Zanesville, OH to points in FL, GA, AL and TX and (b) from Nacogdoches, TX to points in AL, GA and FL for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): McGraw Edison, Power Systems Dvsn., P.O. Box 440, Canonsburg, PA 15317. Send protests to: Donna M. Jones, TA, ICC, BOp, Monterey Bldg., Suite 101, 8410 N.W. 53rd Terr., Miami, FL 33166.

MC 140484 (Sub-421 TA), filed April 12, 1979. Applicant: LESTER COGGINS TRUCKING, INC., 2671 E. Edison Ave., P.O. Box 69, Fort Myers, FL 33902. Representative: Frank T. Day (same address as applicant). *Malt beverages* (except in bulk, in tank vehicles) from Eden, NC, Ft. Worth, TX, and Albany, GA, on the one hand, and, on the other, Ft. Myers, FL for 180 days. Supporting shipper(s): Sunset Distributors, Inc., 3404 Cargo St., Fort Myers, FL 33901. Send protests to: Donna M. Jones, T/A, Interstate Commerce Commission, Monterey Bldg., Suite 101, 8410 N.W. 53rd Terr., Miami, FL 33166.

MC 140615 (Sub-67 TA), filed April 5, 1979. Applicant: DAIRYLAND TRANSPORT, INC. P.O. Box 1116, Wisconsin Rapids, WI 54494. Representative: Terrence Jones, 2033 K St. NW., Washington, DC 20006. *Foodstuffs* from the facilities of Campbell Soup Co. at Napoleon, OH to points in KY, NY, PA, TN, VA, WI & WV and Chicago, IL and Camden, NJ, for 180 days. Supporting shipper(s): Campbell Soup Co., E. Maumee Ave. Napoleon, OH 43545. Send protests to: Gail Daugherty, Transportation Asst., Interstate Commerce Commission, Bureau of Operations, U.S. Federal Building & Courthouse, 517 East Wisconsin Ave., Rm 619, Milwaukee, WI 53202.

MC 140615 (Sub-38 TA), filed April 5, 1979. Applicant: DAIRYLAND TRANSPORT, INC. P.O. Box 1116, Wisconsin Rapids, WI 54494. Representative: Terrence D. Jones, 2033 K St. NW., Washington, DC 20006. *Cheese* from Cabot, VT to Wisconsin Rapids, WI, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Brooke Bond Cheez Co., Inc., 2321 Jefferson St., Wisconsin Rapids, WI 54494. Send protests to: Gail Daugherty, Transportation Asst., Interstate Commerce Commission, Bureau of Operations, U.S. Federal Building & Courthouse, 517 East Wisconsin Ave., Rm 619, Milwaukee, WI 53202.

MC 140615 (Sub-39TA), filed April 5, 1979. Applicant: DAIRYLAND TRANSPORT, INC., P.O. Box 1116, Wisconsin Rapids, WI 54494. Representative: Dennis Brown (same address as applicant). *Canned goods* from Arlington, Augusta, Bear Creek, Belgium, Cambria, Cleveland, Clymar Durand Eagle River, Eden, Fairwater, Fond du Lac, Galesville, Gillette, Green Bay, Lodi, Lomira, Loyal, Manitowoc, Markesan, Marshfield, Mondovi, New Richmond, Oakfield Pickett, Plover, Poynette, Pulaski, Random Lake, Reedsburg, Sauk City, Seymour, Susse, Theresa, WI to points in AL, CT, DE, GA, IL, IN, IA, KS, KY, MD, MA MI, MN, MO, NE, NJ, NY, NC, OH, OK, PA, RI, SC, TN, VA & WV, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): American Farms Cooperative, Inc., P.O. Box 311, Waupun, WI 53963. Send protests to: Gail Daugherty, TA, ICC, Bureau of Operations, U.S. Federal Bldg & Courthouse, 517 East Wisconsin Ave., Rm 619, Milwaukee, WI 53202.

MC 140615 (Sub-40TA), filed April 13, 1979. Applicant: DAIRYLAND TRANSPORT, INC., P.O. Box 1116, Wisconsin Rapids, WI 54494. Representative: Terrence Jones, 2033 K St., NW., Washington, DC 20006. *Lighting fixtures, and parts and accessories of lighting fixtures,* (1) from the facilities of Keystone Lighting Corp., at Bristol, PA to the commercial zones of Chicago, IL; Indianapolis, IN; Kansas City, KS; Detroit, MI; Minneapolis, MN; St. Louis, MO; Omaha, NE; Cleveland, OH and Milwaukee, WI; and (2) from the Chicago, IL commercial zone to the facilities of Keystone Lighting Corp. at Bristol, PA, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Keystone Lighting Corp., Beaver St. & Rt. 13, Bristol, PA 19007. Send protests to: Gail Daugherty, TA, ICC, Bureau of Operations, U.S. Federal Bldg & Courthouse, 517 East Wisconsin Ave., Rm 619, Milwaukee WI 53202.

MC 141205 (Sub-15TA), filed April 26, 1979. Applicant: HUSKY OIL TRANSPORTATION COMPANY, 600 South Cherry Street, Denver, CO 80222. Representative: F. Robert Reeder and James M. Elegante, P.O. Box 11898, Salt Lake City, UT 84147. *Contract-irregular-Crude oil, Scrubber oil and condensate,* from Grand County, Utah, to Chevron Pipeline injection station at Rangely, CO and the Gary Western Refinery, Fruita, CO, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Husky Oil Company, 600 South Cherry Street, Denver, CO 80222. Send protests to: Herbert C. Ruoff, District Supervisory, 492 U.S. Customs House, 721 19th Street, Denver, CO 80202.

MC 141205 (Sub.16TA), filed April 26, 1979. Applicant: HUSKY OIL TRANSPORTATION COMPANY, 600 South Cherry Street, Denver, CO 80222. Representative: F. Robert Reeder and James M. Elegante, P.O. Box 11898, Salt Lake City, Utah 84147. *Contract-irregular-Crude oil, scrubber oil and condensate,* from Clay Basin, Daggett County, UT, to delivery point at North Baxter pipeline station, Rock Springs, WY, for 180 days. Supporting shipper(s): Husky Oil Company, 600 South Cherry Street, Denver, Colorado 80222. Send protests to: District Supervisor Herbert C. Ruoff, 492 U.S. Customs House, 721 19th Street, Denver, Colorado 80202.

MC 141774 (Sub-23TA), filed April 25, 1979. Applicant: R & L TRUCKING CO., INC., 105 Rocket Avenue, Opelika, AL 36801. Representative: Robert E. Tate, P.O. Box 517, Evergreen, AL 36401. *(1) Charcoal, charcoal briquets, vermiculite, active carbon, and hickory chip charcoal lighter fluid, and charcoal grills and accessories* between points in the States of MS, KY, AL, FL, TN, GA, NC, SC, and MO, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Husky Industries, Inc., 62 Perimeter Center, East, Atlanta, GA 30346. Send protests to: Mabel Holston, T/A, Room 1616, 2121 Building, Birmingham, AL 35203.

MC 141804 (Sub-215TA), filed April 16, 1979. Applicant: WESTERN EXPRESS, DIVISION OF INTERSTATE RENTAL, INC., P.O. Box 3488, Ontario, CA 91761. Representative: Frederick J. Coffman, P.O. Box 3488, Ontario, CA 91761. *Batteries, scrap batteries, parts, attachments, accessories and supplies used in connection with batteries, and equipment, materials and supplies used in the manufacture or distribution of batteries,* between the facilities of Chloride Company, Inc., located at or near Florence, MS; Columbus, GA; Raleigh, NC; Tampa, FL; and Beaverton, OR on the one hand, and, on the other, points in the United States, for 180 days. An underlying ETA seeks up to 90 days operating authority. Supporting shipper(s): Chloride Incorporated, 3507 South 50th Street, Tampa, FL 33601. Send protests to: Irene Carlos, Transportation Assistant, Interstate Commerce Commission, P.O. Box 1551, Los Angeles, CA 90053.

MC 141914 (Sub-56TA), filed April 19, 1979. Applicant: FRANKS AND SON, INC., Route 1, Box 108A, Big Cabin, OK 74332. Representative: Kathrena J. Franks, (same address as applicant). *Fruit juice concentrates or fruit juices, frozen or chilled,* (except in bulk), in vehicles equipped with mechanical refrigeration, from Ontario, CA, to points in OH, MN, IA, MO, MI, GA, AL, IL, MA, MD, VA, NC, LA, & TX, for 180 days. Supporting shipper(s): Green Spot Company, division of Capitol Food Industries, Inc., 520 Mission St., So., Pasadena, CA 91030. Send protests to: District Supervisor, Interstate Commerce Commission, Room 240 Old Post Office & Court House Bldg., 215 N.W. 3rd, Oklahoma City, OK 73102.

MC 142715 (Sub-41TA), filed April 25, 1979. Applicant: LENERTZ, INC., P.O. Box 141, South St. Paul, MN 55075. Representative: K. O. Petrick (same address as applicant). *(1) Such merchandise as is dealt in by department stores; and (2) Foodstuffs in mixed loads with commodities described in (1) above (except commodities in bulk)* from points in the U.S. in and east of ND, SD, NE, CO, NM, and TX (except WI) to Green Bay, WI, restricted to traffic destined to the facilities of Shopko Stores, Inc., Green Bay, WI, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Shopko Stores, Inc., 2800 South Ashland, Green Bay, WI 54303. Send protests to: Delores A. Poe, TA, ICC, 414 Federal Building & U.S. Court House, 110 South 4th Street, Minneapolis, MN 55401.

MC 142715 (Sub-42TA), filed April 10, 1979. Applicant: LENERTZ, INC., P.O. Box 141, South St. Paul, MN 55075. Representative: K. O. Petrick (same address as applicant). *Foodstuffs (except commodities in bulk)* from (1) Minneapolis and New Hope, MN to points in WI, MO, IL, IN, MI, OH, NY, PA, NJ, NC, SC, GA, AL, TN, LA and TX, restricted to traffic originating at the facilities of the Creamette Company at New Hope and Minneapolis, MN and destined to points in the named states; and (2) Fairlawn, NJ and Carnegie, PA to Minneapolis, and New Hope, MN, restricted to traffic originating at Fairlawn, NJ and Carnegie, PA and destined to the facilities of the Creamette Company at Minneapolis and New Hope, MN, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): The Creamette Company, Assistant Traffic Manager, 7300 36th Avenue, New Hope, MN. Send protests to: Delores A. Poe, TA, ICC, 414 Federal Building & U.S. Court House, 110 South 4th Street, Minneapolis, MN 55401.

MC 142715 (Sub-43TA), filed April 16, 1979. Applicant: LENERTZ, INC., P.O. Box 141, South St. Paul, MN 55075. Representative: K. O. Petrick, P.O. Box 141, South St. Paul, MN 55075. *Meat, meat products, meat by-products, articles distributed by meat packinghouses* (except hides and commodities in bulk) and *materials and supplies* used by meat packers in the conduct of their business (except commodities in bulk) between the facilities of Lauridsen Foods, Inc. at or near Britt, IA and the facilities of Armour and Company at Mason City, IA, on the one hand, and on the other, points in the U.S. in and east of ND, SD, NE, CO, OK and TX. Restricted to transportation of shipments originating at or destined to the facilities of Lauridsen Foods, Inc., at Britt, IA and the facilities of Armour and Company at Mason City, IA, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Armour and Company, Greyhound Tower, Phoenix, AZ 85077. Send protests to: Delores A. Poe, ICC, T/A, 414 Federal Building, U.S. Court House, 110 South 4th Street, Minneapolis, MN 55401.

MC 142864 (Sub-16TA), filed April 12, 1979. Applicant: RAY E. BROWN TRUCKING, INC., P.O. Box 501, Massillon, Ohio 44646. Representative: Jerry B. Sellman, 50 West Broad Street, Columbus, Ohio 43215. *Ice cream, ice cream confections, ice confections, dairy products and supplies, packaging and ingredients* used therein between Dunkirk, NY and Coshocton, OH, and from Dunkirk, NY to Detroit, MI, Ft. Wayne, IN and Pittsburgh, PA, for 180 days. An underlying ETA seeks 90 day authority. Supporting shipper(s): Dunkirk Ice Cream Company, Inc., 810 Main Street, Dunkirk, NY 14048. Send protests to: ICC, WM Jr. Green Jr. Federal Bldg., 600 Arch Street, Philadelphia, PA 19106.

MC 142935 (Sub-3TA), filed April 18, 1979. Applicant: PLASTIC EXPRESS, 2999 La Jolla Street, Anaheim, CA 92806. Representative: Richard C. Celio, 1415 West Garvey Avenue, Suite 102, West Covina, CA 91790. *Molybdenum concentrate, ferro molybdenum, copper crystals and fertilizer,* from the Sierrita and Exparanza mine sites of the Duval Corporation at or near Sahuarita, AZ to points in Los Angeles County, CA and Houston, TX, for 180 days. An underlying ETA seeks up to 90 days authority. Supporting shipper(s): Duval Corporation, P.O. Box 2967, Houston, TX 77001. Send protests to: Irene Carlos, Transportation Assistant, Interstate Commerce Commission, P.O. Box 1551, Los Angeles, CA 90053.

MC 142974 (Sub-3TA), filed April 9, 1979. Applicant: SURE TRANSPORT, INC., Industrial Center—P.O. Box G, Lincoln, RI 02865. Representative: David M. Marshall, 101 State Street, Suite 304, Springfield, MA 01103. Contract-irregular, *Toilet preparations, drugs, medicines, hospital supplies* and *such commodities as are dealt in by a manufacturer of health and beauty products,* and *materials and supplies used in the manufacture and distribution of such commodities,* between the facilities of Chesebrough-Pond's at Clinton, CT, on the one hand, and, on the other, the facilities of Chesebrough-Pond's Inc., located at Stone Mountain, GA, Los Angeles, CA, Houston, TX, Monticello and Lafayette, IN, for 180 days. An underlying ETA seeks 90 days authority. Supporting Shipper(s): Chesebrough-Pond's Inc., John Street, Clinton, CT 06413. Send protests to: Gerald H. Curry, District Supervisor, 24 Weybosset Street, Room 102, Providence, RI 02903.

MC 143594 (Sub-7TA), filed April 12, 1979. Applicant: NATIONAL BULK TRANSPORT, INC., P.O. Box 5078, Atlanta, GA 30302. Representative: Warren L. Troupe, 2480 E. Commercial Blvd., Fort Lauderdale, FL 33308. *Liquid chemicals, in bulk, in tank vehicles* between the facilities of Callaway Chemical Company at Columbus, GA on the one hand, and, on the other, points in AR, KY, LA, MS, NC, SC, TN, and VA for 180 days. Supporting Shipper(s): Callaway Chemical Company, P.O. Box 2335, Columbus, GA 31902. Send protests to: Sara K. Davis TA, ICC 1252 W. Peachtree St., N.W., Room 300, Atlanta, GA 30309.

MC 143995 (Sub-16TA), filed April 12, 1979. Applicant: SLOAN TRANSPORTATION, INC., 6522 W. River Drive, Davenport, IA 52802. Representative: James M. Hodge, 1980 Financial Center, Des Moines, IA 50309. Contract authority. *Materials, ingredients and supplies* used in the manufacture, distribution and sale of such merchandise as is dealt in by wholesale, retail and chain grocery and feed business houses, from points in IL, IN, MO and OH, to Clinton and Davenport, IA, (except in bulk) under continuing contracts with Ralston Purina Company. Restricted to traffic originating at or destined to the facilities of Ralston Purina Company for 180 days. An underlying ETA seeks 90 days authority. Supporting Shipper(s): Ralston Purina Company, Checkerboard Square, St. Louis, MO 63188. Send protests to: Herbert W. Allen, DS, ICC, 518 Federal Bldg., Des Moines, IA 50309.

MC 143594 (Sub-8TA), filed April 16, 1979. Applicant: NATIONAL BULK TRANSPORT, INC., P.O. Box 5078, Atlanta, GA 30302. Representative: Warren L. Troupe, 2480 E. Commercial Blvd., Fort Lauderdale, FL 33308. *Chemicals, in bulk, in tank vehicles* from the facilities of Georgia Pacific Corporation at or near Plaquemine, LA to Crossett, El Dorado, Little Rock, Malvern, and Ashdown, AR; Lufkin, TX; Memphis, TN; Taylorsville and Louisville, MS; Valliant, OK; Russellville, SC; Conway, NC; Brewton, AL; and Palatka, FL, for 180 days. Supporting Shipper(s): Georgia Pacific

Corporation, P.O. Box 629, Plaquemine, LA 70764. Send protests to: Sara K. Davis TA, ICC, 1252 W. Peachtree St., N.W., Room 300, Atlanta, GA 30309.

MC 144234 (Sub-3TA), filed April 12, 1979. Applicant: PDV CARTAGE, INC., Minonk, IL 61760. Representative: Douglas G. Brown, The INB Center—Suite 555, Springfield, IL 62701. *Sulphuric acid,* from the plant site at Swift & Co., in Calumet City, IL to points and places in MI, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s); American Cyanamid Co., Berdan Avenue, Wayne, NJ. Send Protests to: Charles D. Little, District Supervisor, Interstate Commerce Commission, Leland Office Building—Rm. 414, 527 E. Capitol Ave., Springfield, IL 62701.

MC 146794 (Sub-1TA), filed April 20, 1979. Applicant: PACIFIC NORTHWEST CONTRACT CARRIERS, INC., 3010 N. Jackson Highway, Sheffield, AL 35660. Representative: Nick I. Goyak, 555 Benjamin Frankling Plaza, 1 SW Columbia, Portland, OR 97258. Contract, irregular: *Trailer axles, and parts, suspensions, landing gears, fifth wheels, hitches, and parts thereof, and mechanical refrigeration units,* from Detroit, Lansing and Holland, MI; Chicago, IL; Winamac and Lebanon, IN; Siloam Springs, AR; Montgomery, AL; Denmark, SC; Louisville, GA and Springfield, MO; to Billings, MT; Powell, WY; Salt Lake City, UT; Wilbur, Redmond, Bend and Portland, OR; Seattle, Moses Lake, Spokane and Wilbur, WA and Boise and Buhl, ID, for 180 days. An underlying ETA seeks 90 days authority. Supporting Shipper(s): Standard Parts & Equipment Co., 5251 SE McLoughlin Blvd., Portland, OR 97202. Send protests to: Mabel E. Holston, T/A, ICC, Room 1616 – 2121 Building, Birmingham, AL 35203.

MC 146954 (Sub-1TA), filed April 16, 1979. Applicant: EDGAR'S GARDEN CENTER, INC., Route 38, Mount Holly, N. J. 08060. Representative: Robert M. Dangel, One Centennial Square, E. Euclid Avenue, Haddonfield, N. J. 08033. *Contract carrier:* irregular routes: *Paint trays/sets; can ends; composite cans,* from Lumberton, NJ to points in PA, NJ and NY, for 180 days. Supporting Shipper(s): Burlington Metal Products, Inc., P.O. Box 146, Lumberton, N. J. 08046. Send protests to: District Supervisor, ICC, 428 East State Street, Room 204, Trenton, N. J. 08608.

MC 147125TA, filed March 19, 1979. Applicant: FRONTIER TRANSPORT, INC., P.O. Box 15751, Salt Lake City, UT 84115. Representative: Byron Thomas (same address as applicant). Contract carrier, irregular route, *Iron or steel grinding balls,* in bulk, from the facilities of CF&I Steel Corporatioin at or near Pueblo, CO to Kennecott Copper Corporation, Magna, UT, for 180 days, An underlying ETA seeks 90 days authority. Supporting shipper(s): Kennecott Copper Corporation, P.O. Box 16600, Salt Lake City, UT 84116. Send protests to: L. D. Helfer, DS, ICC, 5301 Federal Bldg., Salt Lake City, UT 84138.

MC 147134TA), filed March 21, 1979. Applicant: CHARLES JOINER, 104 South Central, Tennille, GA 31087. Representative: Clyde W. Carver, Attorney, P.O. Box 720434, Atlanta, GA 30328. *Contract carrier, irregular routes, insulators and parts* from Sandersville, GA, to all points in the United States, under a continuing contract with Lapp Insulator Division of Interpace Corporation, for 180 days. An underlying ETA seeks 90 days authority. Supporting shipper(s): Lapp Insulator Division of Interpace Corporation, P.O. Box 776, Sandersville, GA 31082. Send protests to: Sara K. Davis, T/A, ICC, 1252 W. Peachtree St., N.W., Rm. 300, Atlanta, GA 30309.

MC 147145TA), filed April 27, 1979. Applicant: James R. Anderson d.b.a., ANDERSON & SONS TRUCKING, 3395 Indian Lane, Reno, NV 89506. Representative: James R. Anderson, Jr. (same as applicant). *General Commodities* (except commodities in bulk, in tank vehicles) between Reno and Sparks, NV on the one hand and on the other, San Francisco, San Mateo, Santa Clara, Contra Costa, Alameda and Sacramento Counties, CA., for 180 days. Supporting shipper(s): There are 6 shippers. Their statements may be examined at the office listed below and headquarters. Send protests to: W. J. Huetig, D.S., I.C.C., 203 Federal Building, 705 N. Plaza St., Carson City, NV 89701.

MC 142114 (Sub-6TA), filed February 27, 1979, and published in **Federal Register** issue of April 9, 1979, and republished as corrected this issue. Applicant: Retail Express, Inc., 9 Stuart Road, Chelmsford, MA 01824. Representative: Francis J. Ortman, 7101 Wisconsin Avenue, Suite 605, Washington, D.C. 20014. Contract irregular: Such commodities as are dealt in by retail department stores (except commodities in bulk and frozen foodstuffs), between points in CT, DE, IN, KY, ME, MD, MA, NH, NJ, NY, NC, OH, PA, RI, TN, and VA, for 180 days. Supporting shipper(s): King's Department Stores, Inc., 150 California Street, Newton, MA 02158. Send protests to: Glenn Eady, ICC, 150 Causeway Street, Room 501, Boston, MA 02114. The purpose of this republication is to show applicant's authority as contract.

MC 144075 (Sub-4TA), filed January 18, 1979, published in the **Federal Register** issue of March 6, 1979, and republished this issue. Applicant: INDUSTRIAL TRANSPORT, INC., 2301 East 65th Street, Cleveland, OH 44104. Representative: Brian S. Stern, Esq., 2425 Wilson Blvd., Arlington, VA 22201. The Motor Carrier Board granted authority in this proceeding on May 4, 1979, to operate as a common carrier by motor vehicle, over irregular routes, transporting: *Aluminum and aluminum articles,* from the facilities of Kaiser Aluminum & Chemical Corporation at or near Ravenswood, WV, to points in AL, AR, CT, DE, FL, GA, IL, IN, IA, KY, LA, ME, MD, MA, MI, MN, MS, MO, NH, NJ, NY, NC, OH, PA, RI, SC, TN, TX, VT, VA, WV, WI, and the District of Columbia. This grant of authority is broader than that reflected in the **Federal Register** on March 6, 1979, which showed that applicant was seeking authority to transport these commodities at or near Ravenswood, WV to points in 32 States and the District of Columbia. This republication adds Florida as another destination State. The Board grant is in accordance with supporting shipper's statement.

By the Commission.

H. G. Homme, Jr.,

Secretary.

[FR Doc. 79-18076 Filed 6-8-79; 8:45 am]

BILLING CODE 7035-01-M

Sunshine Act Meetings

Federal Register
Vol. 44, No. 113
Monday, June 11, 1979

This section of the FEDERAL REGISTER contains notices of meetings published under the "Government in the Sunshine Act" (Pub. L. 94-409) 5 U.S.C. 552b(e)(3).

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1

[M-226, Amdt. 7]

CIVIL AERONAUTICS BOARD.

Notice of addition of items to the June 5, 1979, meeting agenda.

TIME AND DATE: 9:30 a.m., June 5, 1979.

PLACE: Room 1027 (Open); Room 1011 (Closed); 1825 Connecticut Avenue, N.W., Washington, D.C. 20428.

SUBJECT:

1b. Proposed order to require American, TWA and United to file data on the number of seats sold at supercoach fares and total load factors in NYC-LAX/SFO markets, to file copies of advertisements of these fares, and to withhold this information from public disclosure until normal release of equivalent data. (Memo 8890, BCP)

1c. Dockets 35731 and 35686; United Air Lines $108 Transcontinental Fare—Extension of fare until July 1, 1979. (BDA)

STATUS: Open.

PERSON TO CONTACT: Phyllis T. Kaylor, the Secretary (202) 673-5068.

SUPPLEMENTARY INFORMATION: The sudden introduction of new capacity-controlled fares raises potential for abuse. The information required to be filed by this proposed order will help the Board discover the carriers' true practices in marketing these fares. It is essential that this information be obtained from the beginning of the new fares and immediately so that the Board can take protective measures, if they are necessary. Since these matters only became apparent the end of last week, it was not possible to prepare the proposed order earlier. A delay until the next meeting, June 20, 1979, would restrict the Board's ability to correct speedily any abuses that might occur from the start of the marketing of these new fares provided for in Item 1b. Complaints to this fare were filed on Friday, June 1, 1979. The fare expires on June 17, 1979. Since no Board meeting will be held prior to the expiration date of the fare, agency business requires that the Board discuss the extension of the subject fare provided for in Item 1c at the June 5, 1979 meeting. Accordingly, the following Members have voted that agency business requires the addition of Items 1b and 1c to the June 5, 1979 agenda and that no earlier announcement was possible:

Chairman, Marvin S. Cohen
Member, Richard J. O'Melia
Member, Elizabeth E. Bailey
Member, Gloria Schaffer

[S-1154-79 Filed 6-7-79; 9:58 am]

BILLING CODE 6320-01-M

2

FEDERAL ELECTION COMMISSION.

"FEDERAL REGISTER" NO. FR-S-1138.

PREVIOUSLY ANNOUNCED DATE AND TIME: Thursday, June 14, 1979 at 10 a.m.

CHANGE IN MEETING: The following items have been added to the open portion of the meeting:

AO 1979-25 Les Aspin, U.S. House of Representatives.
AO 1979-27 John R. White, Treasurer, Committee for Agricultural Political Education (C-TAPE).
Financial Control and Compliance Manual for Presidential Candidates.

The following item has been deleted from the open portion of the meeting: Budget Execution Report.

PERSON TO CONTACT FOR INFORMATION: Mr. Fred S. Eiland, Public Information Officer, telephone 202-523-4065.

Marjorie W. Emmons,

Secretary to the Commission.

[S-1159-79 Filed 6-7-79; 3:10 pm]

BILLING CODE 6715-01-M

3

June 6, 1979

FEDERAL ENERGY REGULATORY COMMISSION.

TIME AND DATE: 10 a.m., June 13, 1979.

PLACE: 825 North Capitol St., N.E. Washington, D.C. 20426, Hearing Room A.

STATUS: Open.

MATTERS TO BE CONSIDERED: Agenda.

Note.—Items listed on the agenda may be deleted wihtout further notice.

CONTACT PERSON FOR MORE INFORMATION: Kenneth F. Plumb, Secretary, telephone (202) 275-4166.

This is list of matters to be considered by the Commission. It does not include a listing of all papers relevant to the items on the agenda; however, all public documents may be examined in the Office of Public Informaton.

Power Agenda—296th Meeting June 13, 1979, Regular Meeting (10 a.m.)

CAP-1. Project No. 1280, Red Bluff Water Power Control District.
CAP-2. Docket No. ER79-326, Central Area Power Coordination Group Pool.
CAP-3. Docket No. E-9565, *Town of Massena, New York* v. *Niagara Mohawk Power Corporation and Power Authority of the State of New York.*
CAP-4. Project No. 1904, New England Power Co.
CAP-5. Project No. 2047, Niagara Mohawk Power Co.
CAP-6. Docket Nos. ER-77-97, et al., and ER78-78, et al., New England Power Co.
CAP-7. Docket Nos. E-8911 and ER77-532, Gulf Power Co.
CAP-8. Docket Nos. ER78-166, EL78-40, EL78-42 and ER 79-22, Georgia Power Co.
CAP-9. Docket No. ER78-283, South Carolina Electric and Gas Co.
CAP-10. Docket No. ER78-463, Montaup Electric Co.

Gas Agenda—296th Meeting, June 13, 1979, Regular Meeting

CAG-1. Docket Nos. RP71-107 and RP72-127 (PGA79-2), Northern Natural Gas Co.
CAG-2. Docket Nos. RP-79-8 and RP72-32, (PGA 79-1 and 79-1A), Kansas Nebraska Natural Gas Company, Inc.
CAG-3. Docket No. RP79-2, Michgan Wisconsin Pipe Line Co.
CAG-4. Docket No. RP77-60, Michgan Wisconsin Pipe Line Co.
CAG-5. Docket Nos. RP72-122 and RP79-1 (PGA79-1A), Colorado Interstate Gas Co.
CAG-6. Docket Nos. RP72-6 and RP76-38 (Storage), El Paso Natural Gas Co.
Docket Nos. CP76-87, CP77-289 and CP78-172 (J & R Issues), El Paso Natural Gas Co.
CAG-7. Docket Nos. CI79-282, CI-79-284 and CI79-285, Tenneco Exploration, Ltd.
Docket No. CI79-283, Tenneco Exploration II, Ltd.
Docket No. CI79-286, Tenneco Oil Co.

CAG-8. Docket No. CI78-627, Columbia Gas Developement Corp.
CAG-9. Docket No. AR64-2, Texaco, Inc. and Tennessee Gas Pipeline Co., A Division of Tenneco Inc.
CAG-10. Docket No. CI68-815, Phillips Petroleum Co.
CAG-11. Docket No. CI78-1005, Phillips Petroleum Co.
CAG-12. Docket No. CI78-1030, The Superior Oil Co.
CAG-13. Docket Nos. CI78-561, et al., Transco Exploration Co. et al.
CAG-14. Docket No. CP9-128, Colorado Interstate Gas Co.
CAG-15. Docket No. CI79-264, Bruce Calder, Inc.
CAG-16 Texas Eastern Transmission Corp.
CAG-17. Docket No. CP78-262, Sea Robin Pipeline Co., United Gas Pipe Line Co., Southern Natural Gas Co. and Natural Gas Pipeline Co. of America
CAG-18. Docket No. CP79-219, Transcontinental Gas Pipe Line Corp.
CAG-19. Docket No. CP79-155, El Paso Natural Gas Co; Docket No. CP79-243, Arkansas Louisiana Gas Co.
CAG-20. Docket No. CP78-55 Consolidated Gas Supply Corp.
CAG-21. Docket No. CP72-9, Arkansas Louisiana Gas Co; Docket No. CP72-15, Cities Service Gas Co.
CAG-22. Docket No. CP79-238, Texas Eastern Transmission Corp.

Miscellaneous Agenda—296th Meeting, June 13, 1979, Regular Meeting

CAM-1. 404 Referral—Notice of Proposed Withdrawal by DOE from General Public Sale of the Isotope Lithium-7 in the Lithium Hydroxide Monohydrate, Enriched to an Isotopic Purity of 99.9% or Greater.
CAM-2. 404 Referral—Notice of Proposed Increase in the Price of Americium-241.
CAM-3. Docket No. OR78-11 (ICC Docket No. 36553), *Kerr-McGee Refining Corporation v. Texoma Pipe Line Company, et al.*
CAM-4. Docket No. RM79- , Removal of Chapter X From 18 CFR Administrator, Emergency Natural Gas Act.
CAM-5. Docket No. RA79-26, Stephens & Cass.
CAM-6. Consolidated Gas Supply Corp.

Power Agenda—296th Meeting, June 13, 1979, Regular Meeting

I. Licensed Project Matters

P-1. Project No. 2216, Power Authority of the State of New York.

II. Electric Rate Matters

ER-1. Docket Nos. E-7796 and E-7777 (Phase II), Pacific Gas and Electric Co.
ER-2. Docket Nos. ER76-90 and ER76-445, Boston Edison Co.
ER-3. Docket No. EL79-15, Kentucky Utilities Co.
ER-4. Docket Nos. ER76-149 and E-9537, Public Service Co. of Indiana.

Miscellaneous Agenda—296th Meeting, June 13, 1979, Regular Meeting

M-1. Reserved.
M-2. Reserved.
M-3. Proposed Amendment to DOE Procedural Regulations Regarding Stays.
M-4. Docket No. RM79- , Delegation of the Commission's Authority to Various Office Directors.
M-5. Docket No. RM79-3, Final Regulations Implementing the Natural Gas Policy Act of 1978.
M-6. Notice of Well Category Determination by State of Louisiana (JD79-3446 and JD79-3449).
M-7. Notice of Well Category Determination by Louisiana State Office on Conservation (JD79-3495).
M-8. Docket No. RA79-7, McCulloch Gas Processing Corp.
M-9. Docket No. OR79-1, Williams Pipeline Co.

Gas Agenda—296th Meeting, June 13, 1979, Regular Meeting

I. Pipeline Rate Matters

RP-1. Docket No. RP75-74, Transwestern Pipeline Co.
RP-2. Docket No. RP72-133 (PGA 77-2), United Gas Pipe Line Co.
RP-3. Docket Nos. RP72-154 (PGA 78-1), RP76-115 (AP 78-1) and RP72-74 (DCA 78-1), Northwest Pipeline Corporation
RP-4. Docket No. RP74-97 (PGA 78-1), Montana-Dakota Utilities Company
RP-5. Docket No. RP78-12, East Tennessee Natural Gas Company

II. Producer Matters

CI-1. Docket No. RP77-13, Arkansas Louisiana Gas Co.
CI-2. Docket Nos., AR64-2, et al., Ginter, Warren & Co. (Texas Gulf Coast Area).

III. Pipeline Certificate Matters

CP-1. Docket Nos. CP76-492 and CP77-644, National Fuel Gas Supply Corp. and National Gas Storage Corp. Docket Nos. CP77-569, CP77-570 and CP77-571, Tennessee Gas Pipeline Company, a division of Tenneco, Inc.
CP-2. Docket Nos. CP77-421, CP79-15, CP79-44, CP79-49, CP79-51 and CP79-69, Transcontinental Gas Pipe Line Corporation. Docket Nos. CP77-324, CP77-548 and CP78-117, Texas Eastern Transmission Company. Docket Nos. CP77-321, CP78-241 and CP79-73, Southern Natural Gas Company. Docket Nos. CP77-566, Transcontinental Gas Pipe Line Corporation and Michigan Wisconsin Pipe Line Company. Docket Nos. CP77-592 and CP77-639, Trunkline Gas Company. Docket No. CP78-246, Texas Gas Transmission Company. Docket No. CP78-68, Florida Gas Transmission Company.
CP-3. Docket No. CP77-267, Mid-Louisiana Gas Co. and Transcontinental Gas Pipe Line Corp.
CP-4. Docket No. CP79-133, ONG Western Inc.
CP-5. Docket Nos. CP75-140, et al., Pacific Alaska LNG Co., et al. Docket Nos. CP74-160, et al., Pacific Indonesia LNG Co., et al. Docket No. CI78-453, Pacific Lighting Gas Development Co. Docket No. CI78-452, Pacific Simpco Partnership.

Kenneth F. Plumb,
Secretary.

[S-1156-79 Filed 6-7-79; 11:34 am]
BILLING CODE 6740-02-M

4

FEDERAL HOME LOAN BANK BOARD.

TIME AND DATE: 9:30 a.m., June 14, 1979.

PLACE: 1700 G Street, N.W., Sixth Floor, Washington, D.C.

STATUS: Open meeting.

CONTACT PERSON FOR MORE INFORMATION: Franklin O. Bolling (202-377-6677).

MATTERS TO BE CONSIDERED:

Application for Bank Membership and Insurance of Accounts—Tokay Savings & Loan Association, Lodi, California.
Branch Office Application—Midwest Federal Savings & Loan Association, Minot, North Dakota.
Consideration of Designation of Roger Williams as Supervisory Agent.
Application for Bank Membership and Insurance of Accounts—Farmers Savings & Loan Association, Dixon, California.
Consideration of Request for a Commitment to Insure Accounts—Dale Hollow Savings & Loan, Livingston, Tennessee.
Application for Bank Membership and Insurance of Accounts—San Marino Savings & Loan Association, San Marino, California.
Branch Office Application—Beverly Hills Federal Savings & Loan Association, Beverly Hills, California.
Change of Name Application—Home Federal Savings & Loan Association of LaFayette, LaFayette, Alabama.
Preliminary Application for Conversion into a Federal Mutual Association—Wilkes Savings & Loan Association, Wilkesboro, North Carolina.
Branch Office Application—First Federal Savings & Loan Association of Wooster, Wooster, Ohio.
Preliminary Appliation for Conversion to Federal Mutual Charter—Home Savings & Loan Association, Greenville, North Carolina.
Limited Facility Application—State Federal Savings & Loan Association, Beatrice, Nebraska.
Consideration of Rules and Regulations and Related Forms To Implement the Bank Board's Authority To Charter, Examine and Regulate Mutual Savings Banks.
Consideration of Revision and Simplification of the Branch Office Regulations.
Consideration of Regulation Regarding 100-Mile Restriction on Branching.
Consideration of Regulation Regarding Washington, D.C. SMSA Branching.
Consideration of Regulations Regarding 3-4 Family 90 percent Loans.
Consideration of Proposed Policy for Coordination of Resources To Implement CRA.

Consideration of Regulations Regarding Reduction in Reporting Requirements.
Consideration of Regulations Regarding Transactions with Affiliated Persons.

[S-1157-79 Filed 6-7-79 2:52 pm]

BILLING CODE 6720-01-M

5

June 7, 1979.

FEDERAL MINE SAFETY AND HEALTH REVIEW COMMISSION.

TIME AND DATE: 10 a.m., June 14, 1979.

PLACE: Room 600, 1730 K Street, N.W., Washington, D.C.

STATUS: Open.

MATTERS TO BE CONSIDERED: The Commission will consider and act upon the following:

Southern Ohio Coal Co., VINC 79-98. (Petition for Interlocutory Review.)
Local Union No. 5249, *UMWA* v. *Consolidation Coal Co.*, MORG 79-13.
Consolidation Coal Co., HOPE 76-208, IBMA No. 76-94. (Request for voluntary dismissal of appeals.)
Karst-Robbins Coal Co., BARB 74-378-P, IBMA No. 76-95. (Request for voluntary dismissal of appeal.)
Mathies Coal Co., PITT 77-13-P, IBMA No. 77-29. (Request for voluntary dismissal of appeal.)
Helen Mining Co., PITT 77-5 and 77-6, IBMA No. 77-31. (Request for voluntary dismissal of appeal.)
Harman Coal Co., PITT 76X263, IBMA No. 77-55. (Request for voluntary dismissal of appeal.)
Consolidation Coal Co., VINC 77-65 and 77-66, IBMA No. 77-59. (Request for voluntary dismissal of appeal.)

CONTACT PERSON FOR MORE INFORMATION: Joanne Kelley, 202-653-5632.

[S-1160-79 Filed 6-7-79; 3:35 pm]

BILLING CODE 6820-12-M

6

INTERNATIONAL TRADE COMMISSION.

"FEDERAL REGISTER" CITATION OF PREVIOUS ANNOUNCEMENT: 44 FR 32336 (6/5/79).

PREVIOUSLY ANNOUNCED TIME AND DATE OF THE MEETING: 10 a.m., Tuesday, June 12, 1979.

CHANGES IN THE MEETING: In deliberations held June 7, 1979, the Commission, by unanimous consent, voted to change the schedule with respect to items 7 and 8 as follows:

7. Multicellular plastic film (Inv. 337-TA-54)—Briefing (in the morning session) and vote (at 2 p.m.).
8. Carbon steel plate from Poland (Inv. AA1921-203)—Briefing (in the morning session) and vote (at 2 p.m.).

Commissioners Alberger, Moore, Bedell, and Stern determined by unanimous consent that Commission business requires the change in the schedule for these agenda items, and affirmed that no earlier announcement of the change to the agenda was possible, and directed the issuance of this notice at the earliest practicable time. Commissioner Parker was not present for the vote.

CONTACT PERSON FOR MORE INFORMATION: Kenneth R. Mason, Secretary, 202-523-0161.

[S-1158-79 Filed 6-7-79; 3:02 pm]

BILLING CODE 7020-02-M

7

SECURITIES AND EXCHANGE COMMISSION.

"FEDERAL REGISTER" CITATION OF PREVIOUS ANNOUNCEMENTS: 44 FR 31799, June 1, 1979/to be published.

STATUS: Closed meeting; open meeting.

PLACE: Room 825, 500 North Capitol Street, Washington, D.C.

DATES PREVIOUSLY ANNOUNCED: Tuesday May 29, 1979/Friday, June 1, 1979.

CHANGES IN THE MEETING: Rescheduling; Deletion; Addition.

The closed meeting to be held on Tuesday, June 5, 1979, after the 10 a.m. open meeting has been rescheduled for Wednesday, June 6, 1979 at 9 a.m.

The following items were not considered at a closed meeting scheduled for Wednesday, June 6, 1979 at 9 a.m. and has been rescheduled for Tuesday, June 12, 1979, at 10 a.m.:

Institution of injunctive actions.
Settlement of administrative proceedings of an enforcement nature.

The following item will not be considered at an open meeting scheduled on Wednesday, June 6, 1979, at 2:30 p.m.:

Oral argument on application for review by Cook & Co., Inc., L. Howard Cook, and Edmund C. H. Hyun of adverse decisions by the National Association of Securities Dealers, Inc. For further information, please contact R. Moshe Simon at (202) 755-1530.

The following item will not be considered at a closed meeting scheduled on Wednesday, June 6, 1979 after the 2:30 p.m. open meeting:

Post oral argument discussion.

The following additional item will be considered at a closed meeting scheduled on Wednesday, June 13, 1979, after the 10 a.m. open meeting:

Institution of administrative proceedings of an enforcement nature.
Administrative proceedings of an enforcement nature.
Regulatory matter bearing enforcement implications.

The following item will be considered at an open meeting to be held on Thursday, June 14, 1979, at 2:30 p.m.:

Presentation and discussion with representatives of the Securities Industry Association regarding proposed legislation to amend the Glass-Steagall Act to permit commercial banks to underwrite state and municipal revenue bonds. For further information, please contact Michael Rogan at (202) 755-1638.

Commissioners Loomis, Evans, and Karmel determined that Commission business required the above changes and that no earlier notice thereof was possible.

At times changes in Commission priorities require alterations in the scheduling of meeting items. For further information and to ascertain what, if any, matters have been added, deleted or postponed, please contact: Mike Rogan at (202) 755-1638.

June 6, 1979.

[S-1155-79 Filed 6-7-79; 10:17 am]

BILLING CODE 8010-01-M

8

TENNESSEE VALLEY AUTHORITY.

TIME AND DATE: 9:30 a.m., June 14, 1979 (Meeting No. 1220).

PLACE: The University of North Carolina-Asheville, Student Center Auditorium, University Hights, Asheville, North Carolina.

STATUS: Open.

MATTERS FOR ACTION:

Old Business

1. Final rate review.

New Business

Personnel Actions

1. Change of status for Donald W. Cramer from Acting Director of Management Systems to Director of Management Systems, Office of Management Services, Knoxville, Tennessee.*
2. Change of status for Ernest A. Belvin, Jr., from Chief, Radiological Hygiene Branch, to Acting Director, Division of Occupational Health and Safety, Office of Management Services, Muscele Shoals, Alabama.*

Consulting and Personal Services Contracts

1. Renewal of personal service contract with Kenneth D. McCasland, Knoxville, Tennessee—Appeals Officer under standard disputes clause of TVA procurement contracts.
2. Renewal of personal service contract with Kenneth L. Penegar, Knoxville,

*These items were approved by individual Board members. This would give formal ratification to the Board's action.

Tennessee—Appeals Officer under standard disputes clause of TVA procurement contracts.

3. Renewal of personal service contract with Richard S. Wirtz, Knoxville, Tennessee—Appeals Officer under standard disputes clause of TVA procurement contracts.

Purchase Awards

1. Negotiation for procurement of an atmospheric fluidized bed combustion pilot plant in lieu of formal advertising.

2. Req. No. 824692—Indefinite quantity term contract for pipe, fittings, flanges, tubing, and accessories for Yellow Creek Nuclear Plant.

3. Req. No. 108234—Galvanized structural tower steel for various transmission lines.

4. Req. No. 108204—Construction of a 24.4-mile section of the West Point-Miller 500-kV Transmission Line.

5. Req. No. 589854—Indefinite quantity term contract for welding electrodes for any TVA nuclear plant.

6. Sales Invitation No. 4048—Sale by TVA of scrap metal and scrap admiralty tubing located at Bellefonte Nuclear Plant and Power Stores, Gallatin Steam Plant.

Project Authorizations

1. No. 3430—Installation of coal ignition and load supplement system at Bull Run Steam Plant.

2. No. 3158.2—Amendment to Ionizer Project at Shawnee Steam Plant (in collaboration with Electric Power Research Institute and Air Pollution Systems).

3. No. 3441—Power System Load Research Program to determine hourly load characteristics of residential, commercial, and industrial consumers at five geographic locations in the TVA power service area.

4. No. 3293.3—Amendment to solar energy research, development, and demonstration in the TVA area.

Power Items

1. Lease and Amendatory Agreement with the city of Amory, Mississippi—TVA's Amory District Substation.

2. Letter Agreement with Alabama Power Co. for Probable Delay in Completing the West Point 500-kV Interconnection at West Point, Mississippi.

3. Supplement to Memorandum Governing Power Supply to the Office of Agricultural and Chemical Development at Wilson Dam.

Real Property Transactions

1. Filing of condemnation suits.

2. Sale of spur railroad track easement affecting approximately 0.37 acre of the Gallatin Steam Plant Access railroad property in Sumner County, Tennessee—Tract XGSPRR–1RR.

3. Grant of permanent highway easement to the city of Soddy-Daisy affecting TVA's Sequoyah Nuclear Plant fee-owned temporary access road and railroad right of way in Hamilton County, Tennessee—Tract XSNPRR–3H.

Unclassified

1. Settlement of litigation brought by Webster County Coal Corp. against TVA and the Louisville & Nashville Railroad Co.*

2. Settlement of *Tennessee Valley Authority* v. *Westinghouse Electric Corporation* (Uranium Contracts Litigation).*

3. Letter agreement with Loudon County, Tennessee, covering arrangements for settlement of claims for repairs to Davis School Road necessitated by construction of Tellico Parkway.

4. Designation of Mary R. Hartman as Certifying Officer.

5. Memorandum of agreement between Tennessee Valley Authority and U.S. Environmental Protection Agency covering arrangement for coordination of environmental improvement programs.*

6. Establishment of Office of Small and Disadvantaged Business Utilization and designation of director to be responsible for implementation and execution of TVA's Small Business Program.*

7. Interagency agreement with U.S. Department of Energy for assessment of electric and magnetic field effects of 500-kV lines.

Dated: June 7, 1979.

CONTACT PERSON FOR MORE INFORMATION: James L. Bentley, Director of Information, or a member of his staff can respond to requests for information about this meeting. Call (615) 632–3257, Knoxville, Tennessee. Information is also available at TVA's Washington Office, (202) 566–1401.

[S-1161-79 Filed 6-7-79; 3:41 pm]

BILLING CODE 8120-01-M

federal register

Monday
June 11, 1979

Part II

Environmental Protection Agency

New Stationary Sources Performance Standards; Electric Utility Steam Generating Units

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL 1240-7]

New Stationary Sources Performance Standards; Electric Utility Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: These standards of performance limit emissions of sulfur dioxide (SO_2), particulate matter, and nitrogen oxides (NO_x) from new, modified, and reconstructed electric utility steam generating units capable of combusting more than 73 megawatts (MW) heat input (250 million Btu/hour) of fossil fuel. A new reference method for determining continuous compliance with SO_2 and NO_x standards is also established. The Clean Air Act Amendments of 1977 require EPA to revise the current standards of performance for fossil-fuel-fired stationary sources. The intended effect of this regulation is to require new, modified, and reconstructed electric utility steam generating units to use the best demonstrated technological system of continuous emission reduction and to satisfy the requirements of the Clean Air Act Amendments of 1977.

DATES: The effective date of this regulation is June 11, 1979.

ADDRESSES: A Background Information Document (BID; EPA 450/3-79-021) has been prepared for the final standard. Copies of the BID may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, N.C. 27711, telephone 919-541-2777. In addition, a copy is available for inspection in the Office of Public Affairs in each Regional Office, and in EPA's Central Docket Section in Washington, D.C. The BID contains (1) a summary of all the public comments made on the proposed regulation; (2) a summary of the data EPA has obtained since proposal on SO_2, particulate matter, and NO_x emissions; and (3) the final Environmental Impact Statement which summarizes the impacts of the regulation.

Docket No. OAQPS-78-1 containing all supporting information used by EPA in developing the standards is available for public inspection and copying between 8 a.m. and 4 p.m., ge a11jn0.005Monday through Friday, at EPA's Central Docket Section, room 2903B, Waterside Mall, 401 M Street, SW., Washington, D.C. 20460.

The docket is an organized and complete file of all the information submitted to or otherwise considered by the Administrator in the development of this rulemaking. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process. Along with the statement of basis and purpose of the promulgated rule and EPA responses to significant comments, the contents of the docket will serve as the record in case of judicial review [section 107(d)(a)].

FOR FURTHER INFORMATION CONTACT: Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, N.C. 27711, telephone 919-541-5271.

SUPPLEMENTARY INFORMATION: This preamble contains a detailed discussion of this rulemaking under the following headings: SUMMARY OF STANDARDS, RATIONALE, BACKGROUND, APPLICABILITY, COMMENTS ON PROPOSAL, REGULATORY ANALYSIS, PERFORMANCE TESTING, MISCELLANEOUS.

Summary of Standards

Applicability

The standards apply to electric utility steam generating units capable of firing more than 73 MW (250 million Btu/hour) heat input of fossil fuel, for which construction is commenced after September 18, 1978. Industrial cogeneration facilities that sell less than 25 MW of electricity, or less than one-third of their potential electrical output capacity, are not covered. For electric utility combined cycle gas turbines, applicability of the standards is determined on the basis of the fossil-fuel fired to the steam generator exclusive of the heat input and electrical power contribution of the gas turbine.

SO_2 Standards

The SO_2 standards are as follows:

(1) Solid and solid-derived fuels (except solid solvent refined coal): SO_2 emissions to the atmosphere are limited to 520 ng/J (1.20 lb/million Btu) heat input, and a 90 percent reduction in potential SO_2 emissions is required at all times except when emissions to the atmosphere are less than 260 ng/J (0.60 lb/million Btu) heat input. When SO_2 emissions are less than 260 mg/J (0.60 lb/million Btu) heat input, a 70 percent reduction in potential emissions is required. Compliance with the emission limit and percent reduction requirements is determined on a continuous basis by using continuous monitors to obtain a 30-day rolling average. The percent reduction is computed on the basis of overall SO_2 removed by all types of SO_2 and sulfur removal technology, including flue gas desulfurization (FGD) systems and fuel pretreatment systems (such as coal cleaning, coal gasification, and coal liquefaction). Sulfur removed by a coal pulverizer or in bottom ash and fly ash may be included in the computation.

(2) Gaseous and liquid fuels not derived from solid fuels: SO_2 emissions into the atmosphere are limited to 340 ng/J (0.80 lb/million Btu) heat input, and a 90 percent reduction in potential SO_2 emissions is required. The percent reduction requirement does not apply if SO_2 emissions into the atmosphere are less than 86 ng/J (0.20 lb/million Btu) heat input. Compliance with the SO_2 emission limitation and percent reduction is determined on a continuous basis by using continuous monitors to obtain a 30-day rolling average.

(3) Anthracite coal: Electric utility steam generating units firing anthracite coal alone are exempt from the percentage reduction requirement of the SO_2 standard but are subject to the 520 ng/J (1.20 lb/million Btu) heat input emission limit on a 30-day rolling average, and all other provisions of the regulations including the particulate matter and NO_x standards.

(4) Noncontinental areas: Electric utility steam generating units located in noncontinental areas (State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, and the Northern Mariana Islands) are exempt from the percentage reduction requirement of the SO_2 standard but are subject to the applicable SO_2 emission limitation and all other provisions of the regulations including the particulate matter and NO_x standards.

(5) Resource recovery facilities: Resource recovery facilities that fire less than 25 percent fossil-fuel on a quarterly (90-day) heat input basis are not subject to the percentage reduction requirements but are subject to the 520 ng/J (1.20 lb/million Btu) heat input emission limit. Compliance with the emission limit is determined on a continuous basis using continuous monitoring to obtain a 30-day rolling average. In addition, such facilities must monitor and report their heat input by fuel type.

(6) Solid solvent refined coal: Electric utility steam generating units firing solid solvent refined coal (SRC I) are subject

to the 520 ng/J (1.20 lb/million Btu) heat input emission limit (30-day rolling average) and all requirements under the NO_x and particulate matter standards. Compliance with the emission limit is determined on a continuous basis using a continuous monitor to obtain a 30-day rolling average. The percentage reduction requirement for SRC I, which is to be obtained at the refining facility itself, is 85 percent reduction in potential SO_2 emissions on a 24-hour (daily) averaging basis. Compliance is to be determined by Method 19. Initial full scale demonstration facilities may be granted a commercial demonstration permit establishing a requirement of 80 percent reduction in potential emissions on a 24-hour (daily) basis.

Particulate Matter Standards

The particulate matter standard limits emissions to 13 ng/J (0.03 lb/million Btu) heat input. The opacity standard limits the opacity of emission to 20 percent (6-minute average). The standards are based on the performance of a well-designed and operated baghouse or electostatic precipitator (ESP).

NO_x Standards

The NO_x standards are based on combustion modification and vary according to the fuel type. The standards are:

(1) 86 ng/J (0.20 lb/million Btu) heat input from the combustion of any gaseous fuel, except gaseous fuel derived from coal;

(2) 130 ng/J (0.30 lb/million Btu) heat input from the combustion of any liquid fuel, except shale oil and liquid fuel derived from coal;

(3) 210 ng/J (0.50 lb/million Btu) heat input from the combustion of subbituminous coal, shale oil, or any solid, liquid, or gaseous fuel derived from coal;

(4) 340 ng/J (0.80 lb/million Btu) heat input from the combustion in a slag tap furnace of any fuel containing more than 25 percent, by weight, lignite which has been mined in North Dakota, South Dakota, or Montana;

(5) Combustion of a fuel containing more than 25 percent, by weight, coal refuse is exempt from the NO_x standards and monitoring requirements; and

(6) 260 ng/J (0.60 lb/million Btu) heat input from the combustion of any solid fuel not specified under (3), (4), or (5).

Continuous compliance with the NO_x standards is required, based on a 30-day rolling average. Also, percent reductions in uncontrolled NO_x emission levels are required. The percent reductions are not controlling, however, and compliance with the NO_x emission limits will assure compliance with the percent reduction requirements.

Emerging Technologies

The standards include provisions which allow the Administrator to grant commercial demonstration permits to allow less stringent requirements for the initial full-scale demonstration plants of certain technologies. The standards include the following provisions:

(1) Facilities using SRC I would be subject to an emission limitation of 520 ng/J (1.20 lb/million Btu) heat input, based on a 30-day rolling average, and an emission reduction requirement of 85 percent, based on a 24-hour average. However, the percentage reduction allowed under a commercial demonstration permit for the initial full-scale demonstration plants, using SRC I would be 80 percent (based on a 24-hour average). The plant producing the SRC I would monitor to insure that the required percentage reduction (24-hour average) is achieved and the power plant using the SRC I would monitor to insure that the 520 ng/J heat input limit (30-day rolling average) is achieved.

(2) Facilities using fluidized bed combustion (FBC) or coal liquefaction would be subject to the emission limitation and percentage reduction requirement of the SO_2 standard and to the particulate matter and NO_x standards. However, the reduction in potential SO_2 emissions allowed under a commercial demonstration permit for the initial full-scale demonstration plants using FBC would be 85 percent (based on a 30-day rolling average). The NO_x emission limitation allowed under a commercial demonstration permit for the initial full-scale demonstration plants using coal liquefaction would be 300 ng/J (0.70 lb/million Btu) heat input, based on a 30-day rolling average.

(3) No more than 15,000 MW equivalent electrical capacity would be allotted for the purpose of commercial demonstration permits. The capacity will be allocated as follows:

Technology	Pollutant	Equivalent electrical capacity MW
Solid solvent-refined coal	SO_2	5,000–10,000
Fluidized bed combustion (atmospheric)	SO_2	400–3,000
Fluidized bed combustion (pressurized)	SO_2	200–1,200
Coal liquefaction	NO_x	750–10,000

Compliance Provisions

Continuous compliance with the SO_2 and NO_x standards is required and is to be determined with continuous emission monitors. Reference methods or other approved procedures must be used to supplement the emission data when the continuous emission monitors malfunction, to provide emissions data for at least 18 hours of each day for at least 22 days out of any 30 successive days of boiler operation.

A malfunctioning FGD system may be bypassed under emergency conditions. Compliance with the particulate standard is determined through performance tests. Continuous monitors are required to measure and record the opacity of emissions. This data is to be used to identify excess emissions to insure that the particulate matter control system is being properly operated and maintained.

Rationale

SO_2 Standards

Under section 111(a) of the Act, a standard of performance for a fossil-fuel-fired stationary source must reflect the degree of emission limitation and percentage reduction achievable through the application of the best technological system of continuous emission reduction taking into consideration cost and any nonair quality health and environmental impacts and energy requirements. In addition, credit may be given for any cleaning of the fuel, or reduction in pollutant characteristics of the fuel, after mining and prior to combustion.

In the 1977 amendments to the Clean Air Act, Congress was severely critical of the current standard of performance for power plants, and especially of the fact that it could be met by the use of untreated low-sulfur coal. The House, in particular, felt that the current standard failed to meet six of the purposes of section 111. The six purposes are (H. Rept. at 184–186):

1. The standards must not give a competitive advantage to one State over another in attracting industry.

2. The standards must maximize the potential for long-term economic growth by reducing emissions as much as practicable. This would increase the amount of industrial growth possible within the limits set by the air quality standards.

3. The standards must to the extent practical force the installation of all the control technology that will ever be necessary on new plants at the time of construction when it is cheaper to install, thereby minimizing the need for retrofit in the future when air quality standards begin to set limits to growth.

4 and 5. The standards to the extent practical must force new sources to burn high-sulfur fuel thus freeing low-sulfur fuel for use in existing sources where it

is harder to control emissions and where low-sulfur fuel is needed for compliance. This will (1) allow old sources to operate longer and (2) expand environmentally acceptable energy supplies.

6. The standards should be stringent in order to force the development of improved technology.

To deal with these perceived deficiences, the House initiated revisions to section 111 as follows:

1. New source performance standards must be based on the "best technological" control system that has been "adequately demonstrated," taking cost and other factors such as energy into account. The insertion of the word "technological" precludes a new source performance standard based solely on the use of low-sulfur fuels.

2. New source performance standards for fossil-fuel-fired sources (e.g., power plants) must require a "percentage reduction" in emissions, compared to the emissions that would result from burning untreated fuels.

The Conference Committee generally followed the House bill. As a result, the 1977 amendments substantially changed the criteria for regulating new power plants by requiring the application of technological methods of control to minimize SO_2 emissions and to maximize the use of locally available coals. Under the statute, these goals are to be achieved through revision of the standards of performance for new fossil-fuel-fired stationary sources to specify (1) an emission limitation and (2) a percentage reduction requirement. According to legislative history accompanying the amendments, the percentage reduction requirement should be applied uniformly on a nationwide basis, unless the Administrator finds that varying requirements applied to fuels of differing characteristics will not undermine the objectives of the house bill and other Act provisions.

The principal issue throughout this rulemaking has been whether a plant burning low-sulfur coal should be required to achieve the same percentage reduction in potential SO_2 emissions as those burning higher sulfur coal. The public comments on the proposed rules and subsequent analyses performed by the Office of Air, Noise and Radiation of EPA served to bring into focus several other issues as well.

These issues included performance capabilities of SO_2 control technology, the averaging period for determining compliance, and the potential adverse impact of the emission ceiling on high-sulfur coal reserves.

Prior to framing the final SO_2 standards, the EPA staff carried out extensive analyses of a range of alternative SO_2 standards using an econometric model of the utility sector. As part of this effort, a joint working group comprised of representatives from EPA, the Department of Energy, the Council of Economic Advisors, the Council on Wage and Price Stability, and others reviewed the underlying assumptions used in the model. The results of these analyses served to identify environmental, economic, and energy impacts associated with each of the alternatives considered at the national and regional levels. In addition, supplemental analyses were performed to assess impacts of alternative emission ceilings on specific coal reserves, to verify performance characteristics of alternative SO_2 scrubbing technologies, and to assess the sulfur reduction potential of coal preparation techniques.

Based on the public record and additional analyses performed, the Administrator concluded that a 90 percent reduction in potential SO_2 emissions (30-day rolling average) has been adequately demonstrated for high-sulfur coals. This level can be achieved at the individual plant level even under the most demanding conditions through the application of flue gas desulfurization (FGD) systems together with sulfur reductions achieved by currently practiced coal preparation techniques. Reductions achieved in the fly ash and bottom ash are also applicable. In reaching this finding, the Administrator considered the performance of currently operating FGD systems (scrubbers) and found that performance could be upgraded to achieve the recommended level with better design, maintenance, and operating practices. A more stringent requirement based on the levels of scrubber performance specified for lower sulfur coals in a number of prevention of significant deterioration permits was not adopted since experience with scrubbers operating with such performance levels on high-sulfur coals is limited. In selecting a 30-day rolling average as the basis for determining compliance, the Administrator took into consideration effects of coal sulfur variability on scrubber performance as well as potential adverse impacts that a shorter averaging period may have on the ability of small plants to comply.

With respect to lower sulfur coals, the EPA staff examined whether a uniform or variable application of the percent reduction requirement would best satisfy the statutory requirements of section 111 of the Act and the supporting legislative history. The Conference Report for the Clean Air Act Amendments of 1977 says in the pertinent part:

> In establishing a national percent reduction for new fossil fuel-fired sources, the conferees agreed that the Administrator may, in his discretion, set a range of pollutant reduction that reflects varying fuel characteristics. Any departure from the uniform national percentage reduction requirement, however, must be accompanied by a finding that such a departure does not undermine the basic purposes of the House provision and other provisions of the act, such as maximizing the use of locally available fuels.

In the face of such language, it is clear that Congress established a presumption in favor of a uniform application of the percentage reduction requirement and that any departure would require careful analysis of objectives set forth in the House bill and the Conference Report.

This question was made more complex by the emergence of dry SO_2 control systems. As a result of public comments on the discussion of dry SO_2 control technology in the proposal, the EPA staff examined the potential of this technology in greater detail. It was found that the development of dry SO_2 controls has progressed rapidly during the past 12 months. Three full scale systems are being installed on utility boilers with scheduled start up in the 1981–1982 period. These already contracted systems have design efficiencies ranging from 50 to 85 percent SO_2 removal, long term average. In addition, it was determined that bids are currently being sought for five more dry control systems (70 to 90 percent reduction range) for utility applications.

Activity in the dry SO_2 control field is being stimulated by several factors. First, dry control systems are less complex than wet technology. These simplified designs offer the prospect of greater reliability at substantially lower costs than their wet counterparts. Second, dry systems use less water than wet scrubbers, which is an important consideration in the Western part of the United States. Third, the amount of energy required to operate dry systems is less than that required for wet systems. Finally, the resulting waste product is more easily disposed of than wet sludge.

The applicability of dry control technology, however, appears limited to low-sulfur coals. At coal sulfur contents greater than about 1290 ng/J (3 pounds SO_2/million Btu), or about 1.5 percent sulfur coal, available data indicate that it probably will be more economical to employ a wet scrubber than a dry control system.

Faced with these findings, the Administrator had to determine what effect the structure of the final regulation would have on the continuing development and application of this technology. A thorough engineering review of the available data indicated that a requirement of 90 percent reduction in potential SO_2 emissions would be likely to constrain the full development of this technology by limiting its potential applicability to high alkaline content, low-sulfur coals. For non-alkaline, low-sulfur coals, the certainty of economically achieving a 90 percent reduction level is markedly reduced. In the face of this finding, it would be unlikely that the technology would be vigorously pursued for these low alkaline fuels which comprise approximately one half of the Nation's low-sulfur coal reserves. In view of this, the Administrator sought a percentage reduction requirement that would provide an opportunity for dry SO_2 technology to be developed for all low-sulfur coal reserves and yet would be sufficiently stringent to assure that the technology was developed to its fullest potential. The Administrator concluded that a variable control approach with a minimum requirement of 70 percent reduction potential in SO_2 emissions (30-day rolling average) for low-sulfur coals would fulfill this objective. This will be discussed in more detail later in the preamble. Less stringent, sliding scale requirements such as those offered by the utility industry and the Department of Energy were rejected since they would have higher associated emissions, would not be significantly less costly, and would not serve to encourage development of this technology.

In addition to promoting the development of dry SO_2 systems, a variable approach offers several other advantages often cited by the utility industry. For example, if a source chose to employ wet technology, a 70 percent reduction requirement serves to substantially reduce the energy impact of operating wet scrubbers in low-sulfur coals. At this level of wet scrubber control, a portion of the untested flue gas could be used for plume reheat so as to increase plume buoyancy, thus reducing if not eliminating the need to expend energy for flue gas reheat. Further, by establishing a range of percent reductions, a variable approach would allow a source some flexibility particularly when selecting intermediate sulfur content coals. Finally, under a variable approach, a source could move to a lower sulfur content coal to achieve compliance if its control equipment failed to meet design expectations. While these points alone would not be sufficient to warrant adoption of a variable standard, they do serve to supplement the benefits associated with permitting the use of dry technology.

Regarding the maximum emission limitation, the Administrator had to determine a level that was appropriate when a 90 percent reduction in potential emissions was applied to high-sulfur coals. Toward this end, detailed assessments of the potential impacts of a wide range of emission limitations on high-sulfur coal reserves were performed. The results revealed that a significant portion (up to 30 percent) of the high-sulfur coal reserves in the East, Midwest and portions of the Northern Appalachia coal regions would require more than a 90 percent reduction if the emission limitation were established below 520 ng/J (1.2 lb/million Btu) heat input on a 30-day rolling average basis. Although higher levels of control are technically feasible, conservatism in utility perceptions of scrubber performance could create a significant disincentive against the use of these coals and disrupt the coal markets in these regions. Accordingly, the Administrator concluded the emission limitation should be maintained at 520 ng/J (1.2 lb/million Btu) heat input on a 30-day rolling average basis. A more stringent emission limit would be counter to one of the purposes of the 1977 Amendments, that is, encouraging the use of higher sulfur coals.

Having determined an appropriate emission limitation and that a variable percent reduction requirement should be established, the Administrator directed his attention to specifying the final form of the standard. In doing so, he sought to achieve the best balance in control requirements. This was accomplished by specifying a 520 ng/J (1.2 lb/million Btu) heat input emission limitation with a 90 percent reduction in potential SO_2 emissions except when emissions to the atmosphere were reduced below 260 ng/J (0.6 lb/million Btu) heat input (30-day rolling average), when only a 70 percent reduction in potential SO_2 emissions would apply. Compliance with each of the requirements would be determined on the basis of a 30-day rolling average. Under this approach, plants firing high-sulfur coals would be required to achieve a 90 percent reduction in potential emissions in order to comply with the emission limitation. Those using intermediate- or low-sulfur content coals would be permitted to achieve between 70 and 90 percent reduction, provided their emissions were less than 260 ng/J (0.6 lb/million Btu). The 260 ng/J (0.6 lb/million Btu) level was selected to provide for a smooth transition of the percentage reduction requirement from high- to low-sulfur coals. Other transition points were examined but not adopted since they tended to place certain types of coal at a disadvantage.

By fashioning the SO_2 standard in this manner, the Administrator believes he has satisfied both the statutory language of section 111 and the pertinent part of the Conference Report. The standard reflects a balance in environmental, economic, and energy considerations by being sufficiently stringent to bring about substantial reductions in SO_2 emissions (3 million tons in 1995) yet does so at reasonable costs without significant energy penalties. When compared to a uniform 90 percent reduction, the standard achieves the same emission reductions at the national level. More importantly, by providing an opportunity for full development of dry SO_2 technology the standard offers potential for further emission reductions (100 to 200 thousand tons per year), cost savings (over $1 billion per year), and a reduction in oil consumption (200 thousand barrels per day) when compared to a uniform standard. The standard through its balance and recognition of varying coal characteristics, serves to expand environmentally acceptable energy supplies without conveying a competitive advantage to any one coal producing region. The maintenance of the emission limitation at 520 ng/J (1.2 lb SO_2/million Btu) will serve to encourage the use of locally available high-sulfur coals. By providing for a range of percent reductions, the standard offers flexibility in regard to burning of intermediate-sulfur content coals. By placing a minimum requirement of 70 percent on low-sulfur coals, the final rule encourages the full development and application of dry SO_2 control systems on a range of coals. At the same time, the minimum requirement is sufficiently stringent to reduce the amount of low-sulfur coal that moves eastward when compared to the current standard. Admittedly, a uniform 90 percent requirement would reduce such movements further, but in the Administrator's opinion, such gains would be of marginal value when compared to expected increases in high-sulfur coal production. By achieving a balanced coal demand within the utility sector and by promoting the development of less expensive SO_2 control technology, the final standard will expand environmentally acceptable energy supplies to existing power plants and industrial sources.

By substantially reducing SO_2 emissions, the standard will enhance the potential for long term economic growth at both the national and regional levels. While more restrictive requirements may have resulted in marginal air quality improvements locally, their higher costs may well have served to retard rather than promote air quality improvement nationally by delaying the retirement of older, poorly controlled plants.

The standard must also be viewed within the broad context of the Clean Air Act Amendments of 1977. It serves as a minimum requirement for both prevention of significant deterioration and non-attainment considerations. When warranted by local conditions, ample authority exists to impose more restrictive requirements through the case-by-case new source review process. When exercised in conjunction with the standard, these authorities will assure that our pristine areas and national parks are adequately protected. Similarly, in those areas where the attainment and maintenance of the ambient air quality standard is threatened, more restrictive requirements will be imposed.

The standard limits SO_2 emissions from facilities firing gaseous or liquid fuels to 340 ng/J (0.80 lb/million Btu) heat input and requires 90 percent reduction in potential emissions on a 30-day rolling average basis. The percent reduction does not apply when emissions are less than 86 ng/J (0.20 lb/million Btu) heat input on a 30-day rolling average basis. This reflects a change to the proposed standards in that the time for compliance is changed from the proposed 24-hour basis to a 30-day rolling average. This change is necessary to make the compliance times consistent for all fuels. Enforcement of the standards would be complicated by different averaging times, particularly when more than one fuel is used.

Particulate Matter Standard

The standard for particulate matter limits the emissions to 13 ng/J (0.03 lb/million Btu) heat input and requires a 99 percent reduction in uncontrolled emissions for solid fuels and a 70 percent reduction for liquid fuels. No particulate matter control is necessary for units firing gaseous fuels alone, and a percent reduction is not required. The percent reduction requirements for solid and liquid fuels are not controlling, and compliance with the particulate matter emission limit will assure compliance with the percent reduction requirements.

A 20 percent (6-minute average) opacity limit is included in this standard. The opacity limit is included to insure proper operation and maintenance of the emission control system. If an affected facility were to comply with all applicable standards except opacity, the owner or operator may request that the Administrator, under 40 CFR 60.11(e), establish a source-specific opacity limit for that affected facility.

The standard is based on the performance of a well designed, operated and maintained electrostatic precipitator (ESP) or baghouse control system. The Administrator has determined that these control systems are the best adequately demonstrated technological systems of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, and nonair quality health and environmental impacts and energy requirements).

Electrostatic Precipitators

EPA collected emission data from 21 ESP-equipped steam generating units which were firing low-sulfur coals (0.4–1.9 percent). EPA evaluated emission levels from units burning relatively low-sulfur coal because it is more difficult for an ESP to collect particulate matter emissions generated by the combustion of low-sulfur coal than high-sulfur coal. None of the ESP control systems at the 21 coal-fired steam generators tested were designed to achieve a 13 ng/J (0.03 lb/million Btu) heat input emission level, however, emission levels at 9 of the 21 units were below the standard. All of the units that were firing coal with a sulfur content between 1.0 and 1.9 percent and which had emission levels below the standard had either a hot-side ESP (an ESP located before the combustion air preheater) with a specific collection area greater than 89 square meters per actual cubic meter per second (452 ft^2/1,000 ACFM), or a cold-side ESP (an ESP located after the combustion air preheater) with a specific collection area greater than 85 square meters per actual cubic meter per second (435 ft^2/1,000 ACFM).

ESP's require a larger specific collection area when applied to units burning low-sulfur coal than to units burning high-sulfur coal because the electrical resistivity of the fly ash is higher with low-sulfur coal. Based on an examination of the emission data in the record, it is the Administrator's judgment that when low-sulfur coal is being fired an ESP must have a specific collection area from about 130 (hot side) to 200 (cold side) square meters per actual cubic meter per second (650 to 1,000 ft^2 per 1,000 ACFM) to comply with the standard. When high-sulfur coal (greater than 3.5 percent sulfur) is being fired an ESP must have a specific collection area of about 72 (cold side) square meters per actual cubic meter per second (360 ft^2 per 1,000 ACFM) to comply with the standard.

Cold-side ESP's have traditionally been used to control particulate matter emissions from power plants. The problem of ESP collection of high-electrical-resistivity fly ash from low-sulfur coal can be reduced by using a hot-side ESP. Higher fly ash collection temperatures result in better ESP performance by reducing fly ash resistivity for most types of low-sulfur coal. Reducing fly ash resistivity in itself would decrease the ESP collection plate area needed to meet the standard; however, for a hot-side ESP this benefit is reduced by the increased flue gas volume resulting from the higher flue gas temperature. Although a smaller collection area is required for a hot-side ESP than for a cold side ESP, this benefit is offset by greater construction costs due to the higher quality of materials, thicker insulation, and special design provisions to accommodate the expansion and warping potential of the collection plates.

Baghouses

The Administrator has evaluated data from more than 50 emission test runs conducted at 8 baghouse-equipped coal-fired steam generating units. Although none of these baghouse-controlled units were designed to achieve a 13 Ng/J (0.03 lb/million Btu) heat input emission level, 48 of the test results achieved this level and only 1 test at each of 2 units exceeded 13 Ng/J (0.03 lb/million Btu) heat input. The emission levels at the two units with emission levels above 13 Ng/J (0.03 lb/million Btu) heat input could conceivably be reduced below that level through an improved maintenance program. It is the Administrator's judgment that baghouses with an air-to-cloth ratio of 0.6 actual cubic meter per minute per square meter (2 ACFM/ft^2) will achieve the standard at a pressure drop of less than 1.25 kilopascals (5 in. H_2O). The Administrator has concluded that this air/cloth ratio and pressure drop are reasonable when considering cost, energy, and nonair quality impacts.

When an owner or operator must choose between an ESP and a baghouse to meet the standard, it is the Administrator's judgment that baghouses have an advantage for low-sulfur coal applications and ESP's have an advantage for high-sulfur coal applications. Available data indicate that for low-sulfur coals, ESP's (hot-side or cold-side) require a large collection area and thus ESP control system costs will be higher than baghouse control system costs. For high-sulfur coals, large collection areas are not required for ESP's, and ESP control systems offer cost savings over baghouse control systems.

Baghouses have not traditionally been used at utility power plants. At the time these regulations were proposed, the largest baghouse-controlled coal-fired steam generator for which EPA had particulate matter emission test data had an electrical output of 44 MW. Several larger baghouse installations were under construction and two larger units were initiating operation. Since the date of proposal of these standards, EPA has tested one of the new units. It has an electrical output capacity of 350 MW and is fired with pulverized, subbituminous coal containing 0.3 percent sulfur. The baghouse control system for this facility is designed to achieve a 43 Ng/J (0.01 lb/million Btu) heat input emission limit. This unit has achieved emission levels below 13 Ng/J (0.03 lb/million Btu) heat input. The baghouse control system was designed with an air-to-cloth ratio of 1.0 actual cubic meter per minute per square meter (3.32 ACFM/ft^2) and a pressure drop of 1.25 kilopascals (5 in. H_2O). Although some operating problems have been encountered, the unit is being operated within its design emission limit and the level of the standard. During the testing the power plant operated in excess of 300 MW electrical output. Work is continuing on the control system to improve its performance. Regardless of type, large emission control systems generally require a period of time for the establishment of cleaning, maintenance, and operational procedures that are best suited for the particular application.

Baghouses are designed and constructed in modules rather than as one large unit. The baghouse control system for the new 350 MW power plant has 28 baghouse modules, each of which services 12.5 MW of generating capacity. As of May 1979, at least 26 baghouse-equipped coal-fired utility steam generators were operating, and an additional 28 utility units are planned to start operation by the end of 1982. About two-thirds of the 30 planned baghouse-controlled power generation systems will have an electrical output capacity greater than 150 MW, and more than one-third of these power plants will be fired with coal containing more than 3 percent sulfur. The Administrator has concluded that baghouse control systems have been adequately demonstrated for full-sized utility application.

Scrubbers

EPA collected emission test data from seven coal-fired steam generators controlled by wet particulate matter scrubbers. Emissions from five of the seven scrubber-equipped power plants were less than 21 Ng/J (0.05 lb/million Btu) heat input. Only one of the seven units had emission test results less than 13 Ng/J (0.03 lb/million Btu) heat input. Scrubber pressure drop can be increased to improve scrubber particulate matter removal efficiencies; however, because of cost and energy considerations, the Administrator believes that wet particulate matter scrubbers will only be used in special situations and generally will not be selected to comply with the standards.

Performance Testing

When the standards were proposed, the Administrator recognized that there is a potential for both FGD sulfate carryover and sulfuric acid mist to affect particulate matter performance testing downstream of an FGD system. Data available at the time of proposal indicated that overall particulate matter emissions, including sulfate carryover, are not increased by a properly designed, constructed, maintained, and operated FGD system. No additional information has been received to alter this finding.

The data available at proposal indicated that sulfuric acid mist (H_2SO_4) interaction with Methods 5 or 17 would not be a problem when firing low-sulfur coal, but may be a problem when firing high-sulfur coals. Limited data obtained since proposal indicate that when high-sulfur coal is being fired, there is a potential for sulfuric acid mist to form after an FGD system and to introduce errors in the performance testing results when Methods 5 or 17 are used. EPA has obtained particulate matter emission test data from two power plants that were fired with coals having more than 3 percent sulfur and that were equipped with both an ESP and FGD system. The particulate matter test data collected after the FGD system were not conclusive in assessing the acid mist problem. The first facility tested appeared to experience a problem with acid mist interaction. The second facility did not appear to experience a problem with acid mist, and emissions after the ESP/FGD system were less than 13 ng/J (0.03 lb/million Btu) heat input. The tests at both facilities were conducted using Method 5, but different methods were used for measuring the filter temperature. EPA has initiated a review of Methods 5 and 17 to determine what modifications may be necessary to avoid acid mist interaction problems. Until these studies are completed the Administrator is approving as an optional test procedure the use of Method 5 (or 17) for performance testing before FGD systems. Performance testing is discussed in more detail in the PERFORMANCE TESTING section of this preamble.

The particulate matter emission limit and opacity limit apply at all times, except during periods of startup, shutdown, or malfunction. Compliance with the particulate matter emission limit is determined through performance tests using Methods 5 or 17. Compliance with the opacity limit is determined by the use of Method 9. A continuous monitoring system to measure opacity is required to assure proper operation and maintenance of the emission control system but is not used for continuous compliance determinations. Data from the continuous monitoring system indicating opacity levels higher than the standard are reported to EPA quarterly as excess emissions and not as violations of the opacity standard.

The environmental impacts of the revised particulate matter standards were estimated by using an economic model of the coal and electric utility industries (see discussion under REGULATORY ANALYSIS). This projection took into consideration the combined effect of complying with the revised SO_2, particulate matter, and NO_x standards on the construction and operation of both new and existing capacity. Particulate matter emissions from power plants were 3.0 million tons in 1975. Under continuation of the current standards, these emissions are predicted to decrease to 1.4 million tons by 1995. The primary reason for this decrease in emissions is the assumption that existing power plants will come into compliance with current state emission regulations. Under these standards, 1995 emissions are predicted to decrease another 400 thousand tons (30 percent).

NO_x Standards

The NO_x emission standards are based on emission levels achievable with a properly designed and operated boiler that incorporates combustion modification techniques to reduce NO_x formation. The levels to which NO_x emissions can be reduced with combustion modification depend not only upon boiler operating practice, but also upon the type of fuel burned. Consequently, the Administrator has developed fuel-specific NO_x standards. The standards are presented in this preamble under Summary of Standards.

Continuous compliance with the NO_x standards is required, based on a 30-day rolling average. Also, percent reductions in uncontrolled NO_x emission levels are required. The percent reductions are not controlling, however, and compliance with the NO_x emission limits will assure compliance with the percent reduction requirements.

One change has been made to the proposed NO_x standards. The proposed standards would have required compliance to be based on a 24-hour averaging period, whereas the final standards require compliance to be based on a 30-day rolling average. This change was made because several of the comments received, one of which included emission data, indicated that more flexibility in boiler operation on a day-to-day basis is needed to accommodate slagging and other boiler problems that may influence NO_x emissions when coal is burned. The averaging period for determining compliance with the NO_x limitations for gaseous and liquid fuels has been changed from the proposed 24-hour to a 30-day rolling average. This change is necessary to make the compliance times consistent for all fuels. Enforcement of the standards would be complicated by different averaging times, particularly where more than one fuel is used. More details on the selection of the averaging period for coal appear in this preamble under Comments on Proposal.

The proposed standards for coal combustion were based principally on the results of EPA testing performed at six electric utility boilers, all of which are considered to represent modern boiler designs. One of the boilers was manufactured by the Babcock and Wilcox Company (B&W) and was retrofitted with low-emission burners. Four of the boilers were Combustion Engineering, Inc. (CE) designs originally equipped with overfire air, and one boiler was a CE design retrofitted with overfire air. The six boilers burned a variety of bituminous and subbituminous coals. Conclusions drawn from the EPA studies of the boilers were that the most effective combustion modification techniques for reducing NO_x emitted from utility boilers are staged combustion, low excess air, and reduced heat release rate. Low-emission burners were also effective in reducing NO_x levels during the EPA studies.

In developing the proposed standards for coal, the Administrator also considered the following: (1) data obtained from the boiler manufacturers on 11 CE, three B&W, and three Foster Wheeler Energy Corporation (FW) utility boilers; (2) the results of tests performed twice daily over 30-day periods at three well-controlled utility boilers manufactured by CE; (3) a total of six months of continuously monitored NO_x emission data from two CE boilers located at the Colstrip plant of the Montana Power Company; (4) plans underway at B&W, FW, and the Riley Stoker Corporation (RS) to develop low-emission burners and furnace designs; (5) correspondence from CE indicating that it would guarantee its new boilers to achieve, without adverse side-effects, emission limits essentially the same as those proposed; and (6) guarantees made by B&W and FW that their new boilers would achieve the State of New Mexico's NO_x emission limit of 190 ng/J (0.45 lb/million Btu) heat input.

Since proposal of the standards, the following new information has become available and has been considered by the Administrator: (1) additional data from the boiler manufacturers on four B&W and four RS utility boilers; (2) a total of 18 months of continuously monitored NO_x data from the two CE utility boilers at the Colstrip plant; (3) approximately 10 months of continuously monitored NO_x data from five other CE boilers; (4) recent performance test results for a CE and a RS utility boiler; and (5) recent guarantees offered by CE and FW to achieve an NO_x emission limit of 190 ng/J (0.45 lb/million Btu) heat input in the State of California. This and other new information is discussed in "Electric Utility Steam Generating Units, Background Information for Promulgated Emission Standards" (EPA 450/3-79-021).

The data available before and after proposal indicate that NO_x emission levels below 210 ng/J (0.50 lb/million Btu) heat input are achievable with a variety of coals burned in boilers made by all four of the major boiler manufacturers. Lower emission levels are theoretically achievable with catalytic ammonia injection, as noted by several commenters. However, these systems have not been adequately demonstrated at this time on full-size electric utility boilers that burn coal.

Continuously monitored NO_x emission data from coal-fired CE boilers indicate that emission variability during day-to-day operation is such that low NO_x levels can be maintained if emissions are averaged over 30-day periods. Although the Administrator has not been able to obtain continuously monitored data from boilers made by the other boiler manufacturers, the Administrator believes that the emission variability exhibited by CE boilers over long periods of time is also characteristic of B&W, FW, and RS boilers. This is because the Administrator expects B&W, FW, and RS boilers to experience operational conditions which are similar to CE boilers (e.g., slagging, variations in fuel quality, and load reductions) when burning similar fuel. Thus, the Administrator believes the 30-day averaging time is appropriate for coal-fired boilers made by all four manufacturers.

Prior to proposal of the standards several electric utilities and boiler manufacturers expressed concern over the potential for accelerated boiler tube wastage (i.e., corrosion) during low-NO_x operation of a coal-fired boiler. The severity of tube wastage is believed to vary with several factors, but especially with the sulfur content of the coal burned. For example, the combustion of high-sulfur bituminous coal appears to aggravate tube wastage, particularly if it is burned in a reducing atmosphere. A reducing atmosphere is sometimes associated with low-NO_x operation.

The EPA studies of one B&W and five CE utility boilers concluded that tube wastage rates did not significantly increase during low-NO_x operation. The significance of these results is limited, however, in that the tube wastage tests were conducted over relatively short periods of time (30 days or 300 hours). Also, only CE and B&W boilers were studied, and the B&W boiler was not a recent design, but was an old-style unit retrofitted with experimental low-emission burners. Thus, some concern still exists over potentially greater tube wastage during low-NO_x operation when high-sulfur coals are burned. Since bituminous coals often have high sulfur contents, the Administrator has established a special emission limit for bituminous coals to reduce the potential for increased tube wastage during low-NO_x operation.

Based on discussions with the boiler manufacturers and on an evaluation of all available tube wastage information, the Administrator has established an NO_x emission limit of 260 ng/J (0.60 lb/million Btu) heat imput for the combustion of bituminous coal. The Administrator believes this is a safe level at which tube wastage will not be accelerated by low-NO_x operation. In support of this belief, CE has stated that it would guarantee its new boilers, when equipped with overfire air, to achieve the 260 ng/J (0.60 lb/million Btu) heat input limit without increased tube wastage rates when Eastern bituminous coals are burned. In addition, B&W has noted in several recent technical papers that its low-emission burners allow the furnace to be maintained in an oxidizing atmosphere, thereby reducing the potential for tube wastage when high-sulfur bituminous coals are burned. The other boiler manufacturers have also developed techniques that reduce the potential for tube wastage during low-NO_x operation. Although the amount of tube wastage data available to the Administrator on B&W, FW, and RS boilers is very limited, it is the Administrator's judgement that all three of these manufacturers are capable of designing boilers which would not experience increased tube wastage rates as a result of compliance with the NO_x standards.

Since the potential for increased tube wastage during low-NO_x operation appears to be small when low-sulfur subbituminous coals are burned, the Administrator has established a lower NO_x emission limit of 210 ng/J (0.50 lb/million Btu) heat input for boilers burning subbituminous coal. This limit is consistent with emission data from boilers representing all four manufacturers. Furthermore, CE has stated that it would guarantee its modern boilers to achieve an NO_x limit of 210 ng/J (0.50 lb/million Btu) heat input, without increased tube wastage rates, when subbituminous coals are burned.

The emission limits for electric utility power plants that burn liquid and gaseous fuels are at the same levels as the emission limits originally promulgated in 1971 under 40 CFR Part 60, Subpart D for large steam generators. It was decided that a new study of combustion modification or NO_x flue-gas treatment for oil- or gas-fired electric utility steam generators would not be appropriate because few, if any, of these kinds of power plants are expected to be built in the future.

Several studies indicate that NO_x emissions from the combustion of fuels derived from coal, such as liquid solvent-refined coal (SRC II) and low-Btu synthetic gas, may be higher than those from petroleum oil or natural gas. This is because coal-derived fuels have fuel-bound nitrogen contents that approach the levels found in coal rather than those found in petroleum oil and natural gas. Based on limited emission data from pilot-scale facilities and on the known emission characteristics of coal, the Administrator believes that an achievable emission limit for solid, liquid, and gaseous fuels derived from coal is 210 ng/J (0.50 lb/million Btu) heat input. Tube wastage and other boiler problems are not expected to occur from boiler operation at levels as low as 210 ng/J when firing these fuels because of their low sulfur and ash contents.

NO_x emission limits for lignite combustion were promulgated in 1978 (48 FR 9276) as amendments to the original standards under 40 CFR Part 60, Subpart D. Since no new information on NO_x emission rates from lignite combustion has become available, the emission limits have not been changed for these standards. Also, these emission limits are the same as the proposed.

Little is known about the emission characteristics of shale oil. However, since shale oil typically has a higher fuel-bound nitrogen content than petroleum oil, it may be impossible for a well-controlled unit burning shale oil to achieve the NO_x emission limit for liquid fuels. Shale oil does have a similar nitrogen content to coal, and it is reasonable to expect that the emission control techniques used for coal could also be used to limit NO_x emissions from shale oil combustion. Consequently, the Administrator has limited NO_x emissions from units burning shale oil to 210 ng/J (0.50 lb/million Btu) heat input, the same limit applicable to subbituminous coal, which is the same as proposed. There is no evidence that tube wastage or other boiler problems would result from operation of a boiler at 210 ng/J when shale oil is burned.

The combustion of coal refuse was exempted from the original steam generator standards under 40 CFR Part 60, Subpart D because the only furnace design believed capable of burning certain kinds of coal refuse, the slag tap furnace, inherently produces NO_x emissions in excess of the NO_x standard. Unlike lignite, virtually no NO_x emission data are available for the combustion of coal refuse in slag tap furnaces. The Administrator has decided to continue the coal refuse exemption under the standards promulgated here because no new information on coal refuse combustion has become available since the exemption under Subpart D was established.

The environmental impacts of the revised NO_x standards were estimated by using an economic model of the coal and electric utility industries (see discussion under REGULATORY ANALYSIS). This projection took into consideration the combined effect of complying with the revised SO_2, particulate matter, and NO_x standards on the construction and operation of both new and existing capacity. National NO_x emissions from power plants were 6.8 million tons in 1975 and are predicted to increase to 9.3 million tons by 1995 under the current standards. These standards are projected to reduce 1995 emissions by 600 thousand tons (6 percent).

Background

In December 1971, under section 111 of the Clean Air Act, the Administrator issued standards of performance to limit emissions of SO_2, particulate matter, and NO_x from new, modified, and reconstructed fossil-fuel-fired steam generators (40 CFR 60.40 et seq.). Since that time, the technology for controlling emissions from this source category has improved, but emissions of SO_2, particulate matter, and NO_x continue to be a national problem. In 1976, steam electric generating units contributed 24 percent of the particulate matter, 65 percent of the SO_2, and 29 percent of the NO_x emissions on a national basis.

The utility industry is expected to have continued and significant growth. The capacity is expected to increase by about 50 percent with approximate 300 new fossil-fuel-fired power plant boilers to begin operation within the next 10 years. Associated with utility growth is the continued long-term increase in utility coal consumption from some 400 million tons/year in 1975 to about 1250 million tons/year in 1995. Under the current performance standards for power plants, national SO_2 emissions are projected to increase approximately 17 percent between 1975 and 1995.

Impacts will be more dramatic on a regional basis. For example, in the absence of more stringent controls, utility SO_2 emissions are expected to increase 1300 percent by 1995 in the West South Central region of the country (Texas, Oklahoma, Arkansas, and Louisiana).

EPA was petitioned on August 6, 1976, by the Sierra Club and the Oljato and Red Mesa Chapters of the Navaho Tribe to revise the SO_2 standard so as to require a 90 percent reduction in SO_2 emissions from all new coal-fired power plants. The petition claimed that advances in technology since 1971 justified a revision of the standard. As a result of the petition, EPA agreed to investigate the matter thoroughly. On January 27, 1977 (42 FR 5121), EPA announced that it had initiated a study to review the technological, economic, and other factors needed to determine to what extent the SO_2 standard for fossil-fuel-fired steam generators should be revised.

On August 7, 1977, President Carter signed into law the Clean Air Act Amendments of 1977. The provisions under section 111(b)(6) of the Act, as amended, required EPA to revise the standards of performance for fossil-fuel-fired electric utility steam generators within 1 year after enactment.

After the Sierra Club petition of August 1976, EPA initiated studies to review the advancement made on pollution control systems at power plants. These studies were continued following the amendment of the Clean Air Act. In order to meet the schedule established by the Act, a preliminary assessment of the ongoing studies was made in late 1977. A National Air Pollution Control Techniques Advisory Committee meeting was held on December 13 and 14, 1977, to present EPA preliminary data. The meeting was open to the public and comments were solicited.

The Clean Air Act Amendments of 1977 required the standards to be revised by August 7, 1978. When it appeared that the Administrator would not meet this schedule, the Sierra Club filed a complaint on July 14, 1978, with the U.S. District Court for the District of Columbia requesting injunctive relief to require, among other things, that the Administrator propose the revised standards by August 7, 1978 (Sierra Club v. Costle, No. 78–1297). The Court approved a stipulation requiring the Administrator to (1) deliver proposed regulations to the Office of the Federal Register by September 12, 1978, and (2) promulgate the final regulations within 6 months after proposal (i.e., by March 19, 1979).

The Administrator delivered the proposal package to the Office of the Federal Register by September 12, 1978, and the proposed regulations were published September 19, 1978 (43 FR 42154). Public comments on the proposal were requested by December 15, and a public hearing was held December 12 and 13, the record of which was held open until January 15, 1979. More than 625 comment letters were received on the proposal. The comments were carefully considered, however, the issues could not be sufficiently evaluated in time to promulgate the standards by March 19, 1979. On that date the Administrator and the other parties in Sierra Club v. Costle filed with the Court a stipulation whereby the Administrator would sign and deliver the final standards to the **Federal Register** on or before June 1, 1979.

The Administrator's conclusions and responses to the major issues are presented in this preamble. These regulations represent the Administrator's response to the petition of the Navaho Tribe and Sierra Club and fulfill the rulemaking requirements under section 111(b)(6) of the Act.

Applicability

General

These standards apply to electric utility steam generating units capable of firing more than 73 MW (250 million Btu/hour) heat input of fossil fuel, for which construction is commenced after September 18, 1978. This is principally the same as the proposal. Some minor changes and clarification in the applicability requirements for cogeneration facilities and resource recovery facilities have been made.

On December 23, 1971, the Administrator promulgated, under Subpart D of 40 CFR Part 60, standards of performance for fossil-fuel-fired steam generators used in electric utility and large industrial applications. The standards adopted herein do not apply to electric utility steam generating units originally subject to those standards (Subpart D) unless the affected facilities are modified or reconstructed as defined under 40 CFR 60 Subpart A and this subpart. Similarly, units constructed prior to December 23, 1971, are not subject to either performance standard (Subpart D or Da) unless they are modified or reconstructed.

Electric Utility Steam Generating Units

An electric utility steam generating unit is defined as any steam electric generating unit that is physically connected to a utility power distribution system and is constructed for the purpose of selling more than 25 MW electrical output and more than one third of its potential electrical output capacity. Any steam that is sold and ultimately used to produce electrical power for sale through the utility power distribution system is also included under the standard. The term "potential electrical generating capacity" has been added since proposal and is defined as 33 percent of the heat input rate at the facility. The applicability requirement of selling more than 25 MW electrical output capacity has also been added since proposal.

These standards cover industrial steam electric generating units or cogeneration units (producing steam for both electrical generation and process heat) that are capable of firing more than 73 MW (250 million Btu/hr) heat input of fossil fuel and are constructed for the purpose of selling through a utility power distribution system more than 25 MW electrical output and more than one-third of their potential electrical output capacity (or steam generating capacity ultimately used to produce electricity for sale). Facilities with a heat input rate in excess of 73 MW (250 million Btu/hour) that produce only industrial steam or that generate electricity but sell less than 25 MW electrical output through the utility power distribution system or sell less than one-third of their potential electric output capacity through the utility power distribution system are not covered by these standards, but will continue to be covered under Subpart D, if applicable.

Resource recovery units incorporating steam electric generating units that would meet the applicability requirements but that combust less than 25 percent fossil fuel on a quarterly (90-day) heat-input basis are not covered by the SO_2 percent reduction requirements under this standard. These facilities are subject to the SO_2 emission limitation and all other provisions of the regulation. They are also required to monitor their heat input by fuel type and to monitor SO_2 emissions. If more than 25 percent fossil fuel is fired on a quarterly heat input basis, the facility will be subject to the SO_2 percent reduction requirements. This represents a change from the proposal which did not include such provisions.

These standards cover steam generator emissions from electric utility combined-cycle gas turbines that are capable of being fired with more than 73 MW (250 million Btu/hr) heat input of fossil fuel and meet the other applicability requirements. Electric utility combined-cycle gas turbines that use only turbine exhaust gas to provide heat to a steam generator (waste heat boiler) or that incorporate steam generators that are not capable of being fired with more than 73 MW (250 million Btu/hr) of fossil fuel are not covered by the standards.

Modification/Reconstruction

Existing facilities are only covered by these standards if they are modified or reconstructed as defined under Subpart A of 40 CFR Part 60 and this standard (Subpart Da).

Few, if any, existing facilities that change fuels, replace burners, etc. will be covered by these standards as a result of the modification/reconstruction provisions. In particular, the standards do not apply to existing facilities that are modified to fire nonfossil fuels or to existing facilities that were designed to fire gas or oil fuels and that are modified to fire shale oil, coal/oil mixtures, coal/oil/water mixtures, solvent refined coal, liquified coal, gasified coal, or any other coal-derived fuel. These provisions were included in the proposal but have been clarified in the final standard.

Comments on Proposal

Electric Utility Steam Generating Units

The applicability requirements are basically the same as those in the proposal; electric utility steam generating units capable of firing greater than 73 MW (250 million Btu/hour) heat input of fossil fuel for which construction is commenced after September 18, 1978, are covered. Since proposal, changes have been made to specific applicability requirements for industrial cogeneration facilities, resource recovery facilities, and anthracite coal-fired facilities. These revisions are discussed later in this preamble.

Only a limited number of comments were received on the general applicability provisions. Some commenters expressed the opinion that the standards should apply to both industrial boilers and electric utility steam generating units. Industrial boilers are not covered by these standards because there are significant differences between the economic structure of utilities and the industrial sector. EPA is currently developing standards for industrial boilers and plans to propose them in 1980.

Cogeneration Facilities

Cogeneration facilities are covered under these standards if they have the capability of firing more than 73 MW (250 million Btu/hour) heat input of fossil fuel and are constructed for the purpose of selling more than 25 MW of electricity and more than one-third of their potential electrical output capacity. This reflects a change from the proposed standards under which facilities selling less than 25 MW of electricity through the utility power distribution system may have been covered.

A number of commenters suggested that industrial cogeneration facilities are expected to be highly efficient and that their construction could be discouraged if the proposed standards were adopted. The commenters pointed out that industrial cogeneration facilities are unusual in that a small capacity (10 MW electric output capacity, for example) steam-electric generating set may be matched with a much larger industrial steam generator (larger than 250 million Btu/hr for example). The Administrator intended that the proposed standards cover only electric generation sets that would sell more than 25 MW electrical output on the utility power distribution system. The final standards allow the sale of up to 25 MW electrical output capacity before a facility is covered. Since most industrial cogeneration units are expected to be less than 25 MW electrical output capacity, few, if any, new industrial cogeneration units will be covered by these standards. The standards do cover large electric utility cogeneration facilities because such units are fundamentally electric utility steam generating units.

Comments suggested clarifying what was meant in the proposal by the sale of more than one-third of its "maximum electrical generating capacity". Under the final standard the term "potential electric output capacity" is used in place of "maximum electrical generating capacity" and is defined as 33 percent of the steam generator heat input capacity. Thus, a steam generator with a 500 MW (1,700 million Btu/hr) heat input capacity would have a 165 MW potential electrical output capacity and could sell up to one-third of this potential output capacity on the grid (55 MW electrical output) before being covered under the standard. Under the proposal, it was unclear if the standard allowed the sale of up to one-third of the actual electric generating capacity of a facility or one-third of the potential generating capacity before being covered under the standards. The Administrator has clarified his intentions in these standards. Without this clarification the standards may have discouraged some industrial cogeneration facilities that have low in-house electrical demand.

A number of commenters suggested that emission credits should be allowed for improvements in cycle efficiency at new electric utility power plants. The commenters suggested that the use of electrical cogeneration technology and other technologies with high cycle efficiencies could result in less overall fuel consumption, which in turn could reduce overall environmental impacts through lower air emissions and less solid waste generation. The final standards do not give credit for increases in cycle efficiency because the different technologies covered by the standards and available for commercial application at this time are based on the use of conventional steam generating units which have very similar cycle efficiencies, and credits for improved cycle efficiency would not provide measurable benefits. Although the final standards do not address cycle efficiency, this approach will not discourage the application of more efficient technologies.

If a facility that is planned for construction will incorporate an innovative control technology (including electrical generation technologies with inherently low emissions or high electrical generation efficiencies) the owner or operator may apply to the Administrator under section 111(j) of the Act for an innovative technology waiver which will allow for (1) up to four years of operation or (2) up to seven years after issuance of a waiver prior to performance testing. The technology would have to have a substantial likelihood of achieving greater continuous emission reduction or achieve equivalent reductions at low cost in terms of energy, economics, or nonair quality impacts before a waiver would be issued.

Resource Recovery Facilities

Electric utility steam generating units incorporated into resource recovery facilities are exempt from the SO_2 percent reduction requirements when less than 25 percent of the heat input is from fossil fuel on a quarterly heat input basis. Such facilities are subject to all other requirements of this standard. This represents a change from the proposed regulation, under which any steam electric generating unit that combusts non-fossil fuels such as wood residue, sewage sludge, waste material, or municipal refuse would have been covered if the facility were capable of firing more than 75 MW (250 million Btu/hr) of fossil fuel.

A number of comments indicated that the proposed standard could discourage the construction of resource recovery facilities that generate electricity because of the SO_2 percentage reduction requirement. One commenter suggested that most new resource recovery facilities will process municipal refuse and other wastes into a dry fuel with a low-sulfur content that can be stored and subsequently fired. The commenter suggested that when firing processed refuse fuel, little if any fossil fuel will be necessary for combustion stabilization over the long term; however, fossil fuel will be necessary for startup. When a cold unit is started, 100 percent fossil fuel (oil or gas) may be fired for a few hours prior to firing 100 percent processed refuse.

Other commenters suggested that resource recovery facilities would in many cases be owned and operated by a municipality and the electricity and steam generated would be sold by contract to offset operating costs. Under such an arrangement, commenters suggested that there may be a need to fire fossil fuel on a short-term basis when refuse is not readily available in order to generate a reliable supply of steam for the contract customer.

The Administrator accepts these suggestions and does not wish to discourage the construction of resource recovery facilities that generate electricity and/or industrial steam. For resource recovery facilities, the Administrator believes that less than 25 percent heat input from fossil fuels will be required on a long-term basis; even though 100 percent fossil fuel firing [greater than 73 MW (250 million Btu/hour)] may be necessary for startup or intermittent periods when refuse is not available. During startup such units are allowed to fire 100 percent fossil fuel because periods of startup are exempt from the standards under 40 CFR 60.8(c). If a reliable source of refuse is not available and 100 percent fossil fuel is to be fired more than 25 percent of the time, the Administrator believes it is reasonable to require such units to meet the SO_2 percent reduction requirements. This will allow resource recovery facilities to operate with fossil fuel up to 25 percent of the time without having to install and operate an FGD system.

Anthracite

These standards exempt facilities that burn anthracite alone from the percentage reduction requirements of the SO_2 standard but cover them under the 520 ng/J (1.2 lb/million Btu) heat input emission limitation and all requirements of the particulate matter and NO_x standards. The proposed regulations would have covered anthracite in the same maner as all other coals. Since the Administrator recognized that there were arguments in favor of less stringent requirements for anthracite, this issue was discussed in the preamble to the proposed regulations.

Over 30 individuals or organizations commented on the anthracite issue. Almost all of the commenters favored exempting anthracite from the SO_2 percentage reduction requirement. Some of the reasons cited to justify exemption were: (1) the sulfur content of anthracite is low; (2) anthracite is more expensive to mine and burn than bituminous and will not be used unless it is cost competitive; and (3) reopening the anthracite mines will result in improvement of acid-mine-water conditions, elimination of old mining scars on the topography, eradication of dangerous fires in deep mines and culm banks, and creation of new jobs. One commenter pointed out that the average sulfur content of anthracite is 1.09 percent. Other commenters indicated that anthracite will be cleaned, which will reduce the sulfur content. One commenter opposed exempting anthracite, because it would result in more SO_2 emissions. Another commenter said all coal-fired power plants including anthracite-fired units should have scrubbers.

After evaluating all of the comments, the Administrator has decided to exempt facilities that burn anthracite alone from the percentage reduction requirements of the SO_2 standard. These facilities will be subject to all other requirements of this regulation, including the particulate matter and NO_x standards, and the 520 ng/J (1.2 lb/million Btu) heat imput emission limitation under the SO_2 standard.

In 10 Northeastern Pennsylvania counties, where about 95 percent of the nation's anthracite coal reserves are located, approximately 40,000 acres of land have been despoiled from previous anthracite mining. The recently enacted Federal Surface Mining Control and Reclamation Act was passed to provide for the reclamation of areas like this. Under this Act, each ton of coal mined is taxed at 35 cents for strip mining and 15 cents for deep mining operations. One-half of the amount taxed is automatically returned to the State where the coal mined and one-half is to be distributed by the Department of Interior. This tax is expected to lead eventually to the reclamation of the anthracite region, but restoration will require many years. The reclamation will occur sooner if culm piles are used for fuel, the abandoned mines are reopened, and the expense of reclamation is born directly by the mine operator.

The Federal Surface Mining Control and Reclamation Act and a similar Pennsylvania law also provide for the establishment of programs to regulate anthracite mining. The State of Pennsylvania has assured EPA that total reclamation will occur if anthracite mining activity increases. They are actively pursuing with private industry the development of one area involving 12,000 to 19,000 acres of despoiled land.

In Summary, the Administrator concludes that the higher SO_2 emissions resulting from the use of anthracite without a flue gas desulfurization system is acceptable because of the other environmental improvements that will result. The impact of facilities using anthracite on ambient air quality will be minimized, because they will have to be reviewed to assure compliance with the prevention of significant deterioration provisions under the Act.

Alaskan Coal

The final standards are the same as the proposed; facilities fired with Alaskan coal are covered in the same manner as facilities fired with other coals.

Commenters suggested that problems unique to Alaska justify special provisions for facilities located in Alaska and firing Alaskan coal. Reasons cited as justification for less stringent standards by commenters on the proposal were freezing conditions, problems with sludge disposal, adverse impact of FGD on the reliability of plant operation, low-sulfur content of the coal, and cost impact on the consumer. The Administrator has examined these factors and has concluded that technically and economically feasible means are available to overcome these problems; therefore special regulatory provisions are not justified.

In reaching this conclusion the Administrator considered whether these factors demonstrated that the standards posed a substantially greater burden unique to Alaska. In other northern States where severe freezing conditions are common, plants are enclosed in buildings and insulated vessels and piping provide protection from freezing, both for scrubber operation and for liquid sludge dewatering. For an equivalent electrical generating capacity, the disposal sites for Alaskan plants could be smaller than those for most plants in the contiguous 48 States because of the lower sulfur content of Alaskan coal. Burying pipes carrying sludge to waste ponds below the frost line is feasible, except possibly in permafrost areas. The Administrator expects that future steam generators cannot be sited in permafrost areas because fly ash as well as scrubber sludge could not be properly disposed of in accordance with requirements of the Resource Recovery and Reclamation Act. In permafrost areas, turbines or other non-waste-producing processes are used or electricity is transmitted from other locations.

One commenter pointed out that failures of the FGD system would have an adverse impact on the ability to supply customers with reliable electric service, since there are no extensive interconnections with other utility companies. The Administrator has provided relief from the standards under emergency conditions that would require a choice between meeting a power demand or complying with the standards. These emergency provisions are discussed in a subsequent section of this preamble.

Concern was expressed by the commenters that the cost impact of the standard would be excessive and that the benefits do not justify the cost, especially since Alaskan coal is among the lowest sulfur-content coal in the country. The Administrator agrees that for comparable sulfur-content coals, scrubber operating costs are slightly higher in Alaska because of the transportation costs of required materials such as lime. However, the operating costs are lower than the typical costs of FGD units controlling emissions from higher sulfur coals in the contiguous 48 States.

The Administrator considered applying a less stringent SO_2 standard to Alaskan coal-fired units, but concluded that there is insufficient distinction between conditions in Alaska and conditions in the northern part of the contiguous 48 States to justify such action. The Administrator has concluded that Alaskan coal-fired units should be controlled in the same manner as other facilities firing low-sulfur coal.

Noncontinental Areas

Facilities in noncontinental areas (State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, and the Northern Mariana Islands) are exempt from the SO_2 percentage reduction requirements. Such facilities are required, however, to meet the SO_2 emission limitations of 520 ng/J (1.2 lb/million Btu) heat input (30-day rolling average) for coal and 340 ng/J (0.8 lb/million Btu) heat input (30-day rolling average) for oil, in addition to all requirements under the NO_x and particulate matter standards. This is the same as the proposed standards.

Although this provision was identified as an issue in the preamble to the proposed standards, very few comments were received on it. In general, the comments supported the proposal. The main question raised is whether Puerto Rico has adequate land available for sludge disposal.

After evaluating the comments and available information, the Administrator has concluded that noncontinental areas, including Puerto Rico, are unique and should be exempt from the SO_2 percentage reduction requirements.

The impact of new power plants in noncontinental areas on ambient air quality will be minimized because each will have to undergo a review to assure compliance with the prevention of significant deterioration provisions under the Clean Air Act. The Administrator does not intend to rule out the possibility that an individual BACT or LAER determination for a power plant in a noncontinental area may require scrubbing.

Emerging Technology

The final regulations for emerging technologies are summarized earlier in this preamble under SUMMARY OF STANDARDS and are very similar to the proposed regulations.

In general, the comments received on the proposed regulations were supportive, although a few commenters suggested some changes. A few commenters indicated that section 111(j) of the Act provides EPA with authority to handle innovative technologies. Some commenters pointed out that the proposed standards did not address certain technologies such as dry scrubbers for SO_2 control. One commenter suggested that SRC I should be included under the solvent refined coal rather than coal liquefaction category for purposes of allocating the 15,000 MW equivalent electrical capacity.

On the basis of the comments and public record, the Administrator believes the need still exists to provide a regulatory mechanism to allow a less stringent standard to the initial full-scale demonstration facilities of certain emerging technologies. At the time the standards were proposed, the Administrator recognized that the innovative technology waiver provisions under section 111(j) of the Act are not adequate to encourage certain capital-intensive, front-end control technologies. Under the innovative technology provisions, the Administrator may grant waivers for a period of up to 7 years from the date of issuance of a waiver or up to 4 years from the start of operation of a facility, whichever is less. Although this amount of time may be sufficient to amortize the cost of tail-gas control devices that do not achieve their design control level, it does not appear to be sufficient for amortization of high-capital-cost, front-end control technologies. The proposed provisions were designed to mitigate the potential impact on emerging front-end technologies and insure that the standards do not preclude the development of such technologies.

Changes have been made to the proposed regulations for emerging technologies relative to averaging time in order to make them consistent with the final NO_x and SO_2 standards; however, a 24-hour averaging period has been retained for SRC-I because it has relatively uniform emission rates, which makes a 24-hour averaging period more appropriate than a 30-day rolling average.

Commercial demonstration permits establish less stringent requirements for the SO_2 or NO_x standards, but do not exempt facilities with these permits from any other requirements of these standards.

Under the final regulations, the Administrator (in consultation with the Department of Energy) will issue commercial demonstration permits for the initial full-scale demonstration facilities of each specified technology. These technologies have been shown to have the potential to achieve the standards established for commercial facilities. If, in implementing these provisions, the Administrator finds that a given emerging technology cannot achieve the standards for commercial facilities, but it offers superior overall environmental performance (taking into consideration all areas of environmental impact, including air, water, solid waste, toxics, and land use) alternative standards can be established.

It should be noted that these permits will only apply to the application of this standard and will not supersede the new source review procedures and prevention of significant deterioration requirements under other provisions of the Act.

Modification/Reconstruction

The impact of the modification/reconstruction provisions is the same for the final standard as it was for the proposed standard; existing facilities are only covered by the final standards if the facilities are modified or reconstructed as defined under 40 CFR 60.14, 60.15, or 60.40a. Many types of fuel switches are expressly exempt from modification/reconstruction provisions under section 111 of the Act.

Few, if any, existing steam generators that change fuels, replace burners, etc., are expected to qualify under the modification/reconstruction provisions; thus, few, if any, existing electric utility steam generating units will become subject to these standards.

The preamble to the proposed regulations did not provide a detailed discussion of the modification/reconstruction provisions, and the comments received indicated that these provisions were not well understood by the commenters. The general modification/reconstruction provisions under 40 CFR 60.14 and 60.15 apply to all source categories covered under Part 60. Any source-specific modification/

reconstruction provisions are defined in more detail under the applicable subpart (60.40a for this standard).

A number of commenters expressly requested that fuel switching provisions be more clearly addressed by the standard. In response, the Administrator has clarified the fuel switching provisions by including them in the final standards. Under these provisions existing facilities that are converted to nonfossil fuels are not considered to have undergone modification. Similarly, existing facilities designed to fire gas or oil and that are converted to shale oil, coal/oil mixtures, coal/oil/water mixtures, solvent refined coal, liquified coal, gasified coal, or any other coal-derived fuel are not considered to have undergone modification. This was the Administrator's intention under the proposal and was mentioned in the **Federal Register** preamble for the proposal.

SO_2 Standards

SO_2 Control Technology—The final SO_2 standards are based on the performance of a properly designed, installed, operated and maintained FGD system. Although the standards are based on lime and limestone FGD systems, other commercially available FGD systems (e.g., Wellman-Lord, double alkali and magnesium oxide) are also capable of achieving the final standard. In addition, when specifying the form of the final standards, the Administrator considered the potential of dry SO_2 control systems as discussed later in this section.

Since the standards were proposed, EPA has continued to collect SO_2 data with continuous monitors at two sites and initiated data gathering at two additional sites. At the Conesville No. 5 plant of Columbus and Southern Ohio Electric company, EPA gathered continuous SO_2 data from July to December 1978. The Conesville No. 5 FGD unit is a turbulent contact absorber (TCA) scrubber using thiosorbic lime as the scrubbing medium. Two parallel modules handle the gas flow from a 411-MW boiler firing run-of-mine 4.5 percent sulfur Ohio coal. During the test period, data for only thirty-four 24-hour averaging periods were gathered because of frequent boiler and scrubber outages. The Conesville system averaged 88.8 percent SO_2 removal, and outlet SO_2 emissions averaged 0.80 lb/million Btu. Monitoring of the Wellman-Lord FGD unit at Northern Indiana Public Service Company's Mitchell station during 1978 included one 41-day continuous period of operation. Data from this period were combined with previous data and analyzed. Results indicated 0.61 lb SO_2/million Btu and 89.2 percent SO_2 removal for fifty-six 24-hour periods.

From December 1978 to February 1979, EPA gathered SO_2 data with continuous monitors at the 10-MW prototype unit (using a TCA absorber with lime) at Tennessee Valley Authority's (TVA) Shawnee station and the Lawrence No. 4 FGD unit (using limestone) of Kansas Power and Light Company. During the Shawnee test, data were obtained for forty-two 24-hour periods in which 3.0 percent sulfur coal was fired. Sulfur dioxide removal averaged 88.6 percent. Lawrence No. 4 consists of a 125-MW boiler controlled by a spray tower limestone FGD unit. In January and February 1979, during twenty-two 24-hour periods of operation with 0.5 percent sulfur coal, the average SO_2 removal was 96.6 percent. The Shawnee and Lawrence tests also demonstrated that SO_2 monitors can function with reliabilities above 80 percent. A summary of the recent EPA-acquired SO_2 monitored data follows:

Site	Scrubber	Coal sulfur, pct.	No. of 24-hour periods	Average SO_2 removal, pct.
Conesville No. 5	Thiosorbic lime/TCA	4.5	34	89.2
NIPSCO	Wellman-Lord	3.5	56	89.2
Shawnee	Lime/TCA	3.0	42	88.6
Lawrence No. 4	Limestone/spray tower	0.5	22	96.6

Since proposing the standards, EPA has prepared a report that updates information in the earlier PEDCo report on FGD systems. The report includes listings of several new closed-loop systems.

A variety of comments were received concerning SO_2 control technology. Several comments were concerned with the use of data from FGD systems operating in Japan. These comments suggested that the Japanese experience shows that technology exists to obtain greater than 90 percent SO_2 removal. The commenters pointed out that attitudes of the plant operators, the skill of the FGD system operators, the close surveillance of power plant emissions by the Japanese Government, and technical differences in the mode of scrubber operation were primary factors in the higher FGD reliabilities and efficiencies for Japanese systems. These commenters stated that the Japanese experience is directly applicable to U.S. facilities. Other comments stated that the Japanese systems cannot be used to support standards for power plants in the U.S. because of the possible differences in factors such as the degree of closed-loop versus open-loop operation, the impact of trace constituents such as chlorides, the differences in inlet SO_2 concentrations, SO_2 uptake per volume of slurry, Japanese production of gypsum instead of sludge, coal blending and the amount of maintenance.

The comments on closed-loop operation of Japanese systems inferred that larger quantities of water are purged from these systems than from their U.S. counterparts. A closed-loop system is one where the only water leaving the system is by: (1) evaporative water losses in the scrubber, and (2) the water associated with the sludge. The administrator found by investigating the systems referred to in the comments that six of ten Japanese systems listed by one commenter and two of four coal-fired Japanese systems are operated within the above definition of closed-loop. The closed-loop operation of Japanese scrubbers was also attested to in an Interagencey Task Force Report, "Sulfur Oxides Control Technology in Japan" (June 30, 1978) prepared for Honorable Henry M. Jackson, Chairman, Senate Committee on Energy and Natural Resources. It is also important to note that several of these successful Japanese systems were designed by U.S. vendors.

After evaluating all the comments, the Administrator has concluded that the experience with systems in Japan is applicable to U.S. power plants and can be used as support to show that the final standards are achievable.

A few commenters stated that closed-loop operation of an FGD system could not be accomplished, especially at utilities burning high-sulfur coal and located in areas where rainfall into the sludge disposal pond exceeds evaporation from the pond. It is important to note that neither the proposed nor final standards require closed-loop operation of the FGD. The commenters are primarily concerned that future water pollution regulations will require closed-loop operation. Several of these commenters ignored the large amount of water that is evaporated by the hot exhaust gases in the scrubber and the water that is combined with and goes to disposal with the sludge in a typical ponding system. If necessary, the sludge can be dewatered by use of a mechanical clarifier, filter, or centrifuge and then sludge disposed of in a landfill designed to minimize rainwater collection. The sludge could also be physically or chemically stabilized.

Most U.S. systems operate open-loop (i.e., have some water discharge from their sludge pond) because they are not required to do otherwise. In a recent report "Electric Utility Steam Generating Units—Flue Gas Desulfurization Capabilities as of October 1978" (EPA-450/3-79-001), PEDCo reported that several utilities burning both low- and high-sulfur coal have reported that they are operating closed-loop FGD systems. As discussed earlier, systems in Japan are operating closed-loop if pond disposal is included in the system. Also, experiments at the Shawnee test facility have shown that highly reliable operation can be achieved with high sulfur coal (containing moderate to high levels of chloride) during closed-loop operation. The Administrator continues to believe that although not required, closed-loop operation is technically and economically feasible if the FGD and disposal system are properly designed. If a water purge is necessary to control chloride buildup, this stream can be treated prior to disposal using commercially available water treatment methods, as discussed in the report "Controlling SO_2 Emissions from Coal-Fired Steam-Electric Generators: Water Pollution Impact" (EPA-600/7-78-045b).

Two comments endorsed coal cleaning as an SO_2 emission control technique. One commenter encouraged EPA to study the potential of coal cleaning, and another endorsed coal cleaning in preference to FGD. The Administrator investigated coal cleaning and the relative economics of FGD and coal cleaning and the results are presented in the report "Physical Coal Cleaning for Utility Boiler SO_2 Emission Control" (EPA-600/7-78-034). The Administrator does not consider coal cleaning alone as representing the best demonstrated system for SO_2 emission reduction. Coal cleaning does offer the following benefits when used in conjuction with an FGD system: (1) the SO_2 concentrations entering the FGD system are lower and less variable than would occur without coal cleaning, (2) percent removal credit is allowed toward complying with the SO_2 standard percent removal requirement, and (3) the SO_2 emission limit can be achieved when using a coal having a sulfur content above that which would be needed when coal cleaning is not practiced. The amount of sulfur that can be removed from coal by physical coal cleaning was investigated by the U.S. Department of the Interior ("Sulfur Reduction Potential of the Coals of the United States," Bureau of Mines Report of Investigations/1976, RI-8118). Coal cleaning principally removes pyritic sulfur from coal by crushing it to a maximum top size and then separating the pyrites and other rock impurities from the coal. In order to prevent coal cleaning processes from developing into undesirable sources of energy waste, the amount of crushing and the separation bath's specific gravity must be limited to reasonable levels. The Administrator has concluded that crushing to 1.5 inches topsize and separation at 1.6 specific gravity represents common practice. At this level, the sulfur reduction potential of coal cleaning for the Eastern Midwest (Illinois, Indiana, and Western Kentucky) and the Northern Appalachian Coal (Pennsylvania, Ohio, and West Virginia) regions averages approximately 30 percent. The washability of specific coal seams will be less than or more than the average.

Some comments state that FGD systems do not work on specific coals, such as high-sulfur Illinois-Indiana coal, high-chloride Illinois coal, and Southern Appalachian coals. After review of the comments and data, the Administrator concluded that FGD application is not limited by coal properties. Two reports, "Controlling SO_2 Emissions from Coal-Fired Steam-Electric Generators: Water Pollution Impact" (EPS-600/7-78-045b) and "Flue Gas Desulfurization Systems: Design and Operating Considerations" (EPA-600/7-78-030b) acknowledge that coals with high sulfur or -chloride content may present problems. Chlorides in flue gas replace active calcium, magnesium, or sodium alkalis in the FGD system solution and cause stress corrosion in susceptible materials. Prescrubbing of flue gas to absorb chlorides upstream of the FGD or the use of alloy materials and protective coatings are solutions to high-chloride coal applications. Two reports, "Flue Gas Desulfurization System Capabilities for Coal-Fired Steam Generators" (EPA-600/7-78-032b) and "Flue Gas Desulfurization Systems: Design and Operating Considerations" (EPA-600/7-7-78-030b) also acknowledge that 90 percent SO_2 removal (or any given level) is more difficult when burning high-sulfur coal than when burning low-sulfur coal because the mass of SO_2 that must be removed is greater when high-sulfur coal is burned. The increased load results in larger and more complex FGD systems (requiring higher liquid-to-gas ratios, larger pumps, etc). Operation of current FGD installations such as LaCygne with over 5 percent sulfur coal, Cane Run No. 4 on high-sulfur midwestern coal, and Kentucky Utilities Green River on 4 percent sulfur coal provides evidence that complex systems can be operated successfully on high-sulfur coal. Recent experience at TVA, Widows Creek No. 8 shows that FGD systems can operate successfully at high SO_2 removal efficiencies when Southern Appalachian coals are burned.

Coal blending was the subject of two comments: (1) that blending could reduce, but not eliminate, sulfur variability; and (2) that coal blending was a relatively inexpensive way to meet more relaxed standards. The Administrator believes that coal blending, by itself, does not reduce the average sulfur content of coal but reduces the variability of the sulfur content. Coal blending is not considered representative of the best demonstrated system for SO_2 emission reduction. Coal blending, like coal cleaning, can be beneficial to the operation of an FGD system by reducing the variability of sulfur loading in the inlet flue gas. Coal blending may also be useful in reducing short-term peak SO_2 concentrations where ambient SO_2 levels are a problem.

Several comments were concerned with the dependability of FGD systems and problems encountered in operating them. The commenters suggested that FGD equipment is a high-risk investment, and there has been limited "successful" operating experience. They expressed the belief that utilities will experience increased maintenance requirements and that the possibility of forced outages due to scaling and corrosion would be greater as a result of the standards.

One commenter took issue with a statement that exhaust stack liner problems can be solved by using more expensive materials. The commenter also argued that EPA has no data supporting the assumption that scrubbers have been demonstrated at or near 90 percent reliability with one spare module. The Administrator has considered these comments and has concluded that properly designed and operated FGD systems can perform reliably. An FGD system is a chemical process which must be designed (1) to include materials that will withstand corrosive/erosive conditions, (2) with instruments to monitor process chemistry and (3) with spare capacity to allow for planned downtime for routine maintenance. As with any chemical process, a startup or shakedown period is required before steady, reliable operation can be achieved.

The Administrator has continued to follow the progress of the FGD systems cited in the supporting documents published in conjunction with the proposed regulations in September 1978. Availability of the FGD system at Kansas City Power and Light Company's LaCygne Unit No. 1 has steadily improved. No FGD-related forced outages were reported from September 1977 to September 1978. Availability from January to September 1978 averaged 93 percent. Outages reported were a result of boiler and turbine problems but not FGD system problems. LaCygne Unit No. 1 burns high-sulfur (5 percent) coal, uses one of the earlier FGD's installed in the U.S., and reduces SO_2 emissions by 80 percent with a limestone system at greater than 90 percent availability. Northern States Power Company's Sherburne Units Numbers 1 and 2 on the other hand operate on low-sulfur coal (0.8 percent). Sherburne No. 1, which began operating early in 1976, had 93 percent availability in both 1977 and 1978. Sherburne No. 2, which began operation in late 1976 had availabilities of 93 percent in 1977 and 94 percent in 1978. Both of these systems include spare modules to maintain these high availabilities.

Several comments were received expressing concern over the increased water use necessary to operate FGD systems at utilities located in arid regions. The Administrator believes that water availability is a factor that limits power plant siting but since an FGD system uses less than 10 percent of the water consumed at a power plant, FGD will not be the controlling factor in the siting of new utility plants.

A few commenters criticized EPA for not considering amendments to the Federal Water Pollution Control Act (now the Clean Water Act), the Resource Conservation and Recovery Act, or the Toxic Substances Control Act when analyzing the water pollution and solid waste impacts of FGD systems. To the extent possible, the Administrator believes that the impacts of these Acts have been taken into consideration in this rule-making. The economic impacts were estimated on the basis of requirements anticipated for power plants under these Acts.

Various comments were received regarding the SO_2 removal efficiency achievable with FGD technology. One comment from a major utility system stated that they agreed with the standards, as proposed. Many comments stated that technology for better than 90 percent SO_2 removal exists. One comment was received stating that 95 percent SO_2 removal should be required. The Administrator concludes that higher SO_2 removals are achievable for low-sulfur coal which was the basis of this comment. While 95 percent SO_2 removal may be obtainable on high-sulfur coals with dual alkali or regenerable FGD systems, long-term data to support this level are not available and the Administrator has concluded that the demand for dual alkali/regenerable systems would far exceed vendor capabilities. When the uncertainties of extrapolating performance from 90 to 95 percent for high-sulfur coal, or from 95 percent on low-sulfur coal to high-sulfur coal, were considered, the Administrator concluded that 95 percent SO_2 removal for lime/limestone based systems on high-sulfur coal could not be reasonably expected at this time.

Another comment stated that all FGD systems except lime and limestone were not demonstrated or not universally applicable. The proposed SO_2 standards were based upon the conclusion that they were achievable with a well designed, operated, and maintained FGD system. At the time of proposal, the Administrator believed that lime and limestone FGD systems would be the choice of most utilities in the near future but, in some instances, utilities would choose the more reactive dual alkali or regenerable systems. The use of additives such as magnesium oxides was not considered to be necessary for attainment of the standard, but could be used at the option of the utility. Available data show that greater than 90 percent SO_2 removal has been achieved at full scale U.S. facilities for short-term periods when high-sulfur coal is being combusted, and for long-term periods at facilities when low-sulfur coal is burned. In addition, greater than 90 percent SO_2 removal has been demonstrated over long-term operating periods at FGD facilities when operating on low- and medium-sulfur coals in Japan.

Other commenters questioned the exclusion of dry scrubbing techniques from consideration. Dry scrubbing was considered in EPA's background documents and was not excluded from consideration. Five commercial dry SO_2 control systems are currently on order; three for utility boilers (400–MW, 455–MW, and 550–MW) and two for industrial applications. The utility units are designed to achieve 50 to 85 percent reduction on a long-term average basis and are scheduled to commence operation in 1981–1982. The design basis for these units is to comply with applicable State emission limitations. In addition, dry SO_2 control systems for six other utility boilers are out for bid. However, no full scale dry scrubbers are presently in operation at utility plants so information available to EPA and presented in the background document dealt with prototype units. Pilot scale data and estimated costs of full-scale dry scrubbing systems offer promise of moderately high (70–85 percent) SO_2 removal at costs of three-fourths or less of a comparable lime or limestone FGD system. Dry control system and wet control system costs are approximately equal for a 2-percent-sulfur coal. With lower-sulfur coals, dry controls are particularly attractive, not only because they would be less costly than wet systems, but also because they are expected to require less maintenance and operating staff, have greater turndown capabilities, require less energy consumption for operation, and produce a dry solid waste material that can be more easily disposed of than wet scrubber sludge.

Tests done at the Hoot Lake Station (a 53–MW boiler) in Minnesota demonstrated the performance capability of a spray dryer-baghouse dry control system. The exhaust gas concentrations before the control systems were 800 ppm SO_2 and an average of 2 gr/acf particulate matter. With lime as the sorbent, the control system removed over 86 percent SO_2 and 99.96 percent particulate matter at a stoichiometric ratio of 2.1 moles of lime absorbent per inlet mole of SO_2. When the spent lime dust was recirculated from the bag filter to the lime slurry feed tank, SO_2 removal efficiencies up to 90 percent ware obtained at stoichiometric ratios of 1.3–1.5. With the lime recirculation process, SO_2 removal efficiencies of 70–80 percent were demonstrated at a more economical stoichiometric ratio (about 0.75). Similar tests were performed at the Leland Olds Station using commercial grade lime.

Based upon the available information, the Administrator has concluded that 70 percent SO_2 removal using lime as the reactant is technically feasible and economically attractive in comparison to wet scrubbing when coals containing less than 1.5 percent sulfur are being combusted. The coal reserves which contain 1.5 percent sulfur or less represent approximately 90 percent of the total Western U.S. reserves.

The standards specify a percentage reduction and an emission limit but do not specify technologies which must be used. The Administrator specifically took into consideration the potential of dry SO_2 scrubbing techniques when specifying the final form of the standard in order to provide an opportunity for their development on low-sulfur coals.

Averaging Time

Compiance with the final SO_2 standards is based on a 30-day rolling average. Compliance with the proposed standards was based on a 24-hour average.

Several comments state that the proposed SO_2 percent reduction requirement is attainable using currently available control equipment. One utility company commented upon their experience with operating pilot and prototype scrubbers and a full-scale limestone FGD system on a 550-MW plant. They stated that the FGD state of the art is sufficiently developed to support the proposed standards. Based on their analysis of scrubber operating variability and coal quality variability, they indicated that to achieve an 85 percent reduction in SO_2 emissions 90 percent of the time on a daily basis, the 30-day average scrubber efficiency would have to be at least 88 to 90 percent.

Other comments stated that EPA contractors did not consider SO_2 removal in context with averaging time, that vendor guarantees were not based on specific averaging times, and that quoted SO_2 removal efficiencies were based on testing modules. EPA found through a survey of vendors that many would offer 90–95 percent SO_2 removal guarantees based upon their usual acceptance test criteria. However, the averaging time was not specified. The Industrial Gas Cleaning Institute (IGCI), which represents control equipment vendors, commented that the control equipment industry has the present capability to design, manufacture, and install FGD control systems that have the capability of attaining the proposed SO_2 standards (a continuous 24-hour average basis). Concern was expressed, however, about the proposed 24-hour averaging requirement, and this commenter recommended the adoption of 30-day averaging. Since minute-to-minute variations in factors affecting FGD efficiency cannot be compensated for instantaneously, 24-hour averaging is an impracticably short period for implementing effective correction or for creating offsetting favorable higher efficiency periods.

Numerous other comments were received recommending that the proposed 24-hour averaging period be changed to 30 days. A utility company stated that their experience with operating full scale FGD systems at 500- and 400-MW stations indicates that variations in FGD operation make it extremely difficult, if not impossible, to maintain SO_2 removal efficiencies in compliance with the proposed percent reduction on a continual daily basis. A commenter representing the industry stated that it is clear from EPA's data that the averaging time could be no shorter than 24 hours, but that neither they nor EPA have data at this time to permit a reasonable determination of what the appropriate averaging time should be.

The Administrator has thoroughly reviewed the available data on FGD performance and all of the comments received. Based on this review, he has concluded that to alleviate this concern over coal sulfur variability, particularly its effect on small plant operations, and to allow greater flexibility in operating FGD units, the final SO_2 standard should be based on a 30-day rolling average rather than a 24-hour average as proposed. A rolling average has been adopted because it allows the Administrator to enforce the standard on a daily basis. A 30-day average is used because it better describes the typical performance of an FGD system, allows adequate time for owners or operators to respond to operating problems affecting FGD efficiency, permits greater flexibility in procedures necessary to operate FGD systems in compliance with the standard, and can reduce the effects of coal sulfur variability on maintaining compliance with the final SO_2 standards without the application of coal blending systems. Coal blending systems may be required in some cases, however, to provide for the attainment and maintenance of the National Ambient Air Quality Standards for SO_2.

Emission Limitation

In the September proposal, a 520 ng/J (1.20 lb/million Btu) heat input emission limit, except for 3 days per month, was specified for solid fuels. Compliance was to be determined on a 24-hour averaging basis.

Following the September proposal, the joint working group comprised of EPA, The Department of Energy, the Council of Economic Advisors, the Council on Wage and Price Stability, and others investigated ceilings lower than the proposal. In looking at these alternatives, the intent was to take full advantage of the cost effectiveness benefits of a joint coal washing/scrubbing strategy on high-sulfur coal. The cost of washing is relatively inexpensive; therefore, the group anticipated that a low emission ceiling, which would require coal washing and 90 percent scrubbing, could substantially reduce emissions in the East and Midwest at a relatively low cost. Since coal washing is now a widespread practice, it was thought that Eastern coal production would not be seriously impacted by the lower emission limit. Analyses using an econometric model of the utility sector confirmed these conclusions and the results were published in the **Federal Register** on December 8, 1978 (43 FR 57834).

Recognizing certain inherent limitations in the model when assessing impacts at disaggregated levels, the Administrator undertook a more detailed analysis of regional coal production impacts in February using Bureau of Mines reports which provided seam-by-seam data on the sulfur content of coal reserves and the coal washing potential of those reserves. The analysis identified the amount of reserves that would require more than 90 percent scrubbing of washed coal in order to meet designated ceilings. To determine the sulfur reduction from coal washing, the Administrator assumed two levels of coal preparation technology, which were thought to represent state-of-the-art coal preparation (crushing to 1.5-inch top size with separation at 1.6 specific gravity, and ⅜-inch top size with separation at 1.6 specific gravity). The amount of sulfur reduction was determined according to chemical characteristics of coals in the reserve base. This assessment was made using a model developed by EPA's Office of Research and Development.

As a result of concerns expressed by the National Coal Association, a meeting was called for April 5, 1979, in order for EPA and the National Coal Association to present their respective findings as they pertained to potential impacts of lower emission limits on high-sulfur coal reserves in the Eastern Midwest (Illinois, Indiana, and Western Kentucky) and the Northern Appalachian (Ohio, West Virginia, and Pennsylvania) coal regions. Recognizing the importance of discussion, the Administrator invited representatives from the Sierra Club, the Natural Resources Defense Council, the Environmental Defense Fund, the Utility

Air Regulatory Group, and the United Mine Workers of America, as well as other interested parties to attend.

At the April 5 meeting, EPA presented its analysis of the Eastern Midwest and Northern Appalachian coal regions. The analysis showed that at a 240 ng/J (0.55 lb/million Btu) annual emission limit more than 90 percent scrubbing would be required on between 5 and 10 percent of Northern Appalachian reserves and on 12 to 25 percent of the Eastern Midwest reserves. At a 340 ng/J (0.80 lb/million Btu) limit, less than 5 percent of the reserves in each of these regions would require greater than 90 percent scrubbing. At that same meeting, the National Coal Association presented data on the sulfur content and washability of reserves which are currently held by member companies. While the reported National Coal Association reserves represent a very small portion of the total reserve base, they indicate reserves which are planned to be developed in the near future and provide a detailed property-by-property data base with which to compare EPA analytical results. Despite the differences in data base sizes, the National Coal Association's study served to confirm the results of the EPA analysis. Since the National Coal Association results were within 5 percentage points of EPA's estimates, the Administrator concluded that the Office of Research and Development model would provide a widely accepted basis for studying coal reserve impacts. In addition, as a result of discussions at this meeting the Administrator revised his assessment of state-of-the-art coal cleaning technology. The National Coal Association acknowledged that crushing to 1.5-inch top size with separation at 1.6 specific gravity was common practice in industry, but that crushing to smaller top sizes would create unmanageable coal handling problems and great expense.

In order to explore further the potential for dislocations in regional coal markets, the Administrator concluded that actual buying practices of utilities rather than the mere technical usability of coals should be considered. This additional analysis identified coals that might not be used because of conservative utility attitudes toward scrubbing and the degree of risk that a utility would be willing to take in buying coal to meet the emission limit. This analysis was performed in a similar manner to the analysis described above except that two additional assumptions were made: (1) utilities would purchase coal that would provide about a 10 percent margin below the emission limit in order to minimize risk, and (2) utilities would purchase coal that would meet the emission limit (with margin) with a 90 percent reduction in potential SO_2 emissions. This assumption reflects utility preference for buying washed coal for which only 85 percent scrubbing is needed to meet both the percent reduction and the emission limit as compared to the previous assumption that utilities would do 90 percent scrubbing on washed coal (resulting in more than 90 percent reduction in potential SO_2 emissions). This analysis was performed using EPA data at 430 ng/J (1.0 lb/million Btu) and 520 ng/J (1.20 lb/million Btu) monthly emission limits. The results revealed that a significant portion (up to 22 percent) of the high-sulfur coal reserves in the Eastern Midwest and portions of Northern Appalachian coal regions would require more than a 90 percent reduction if the emission limitation was established below 520 ng/J (1.20 lb/million Btu) on a 30-day rolling average basis. Although higher levels of control are technically feasible, conservatism in utility perceptions of scrubber performance could create a significant disincentive against the use of these coals and disrupt the coal markets in these regions. Accordingly, the Administrator concluded the emission limitation should be maintained at 520 ng/J (1.20 lb/million Btu) on a 30-day rolling average basis. A more stringent emission limit would be counter to one of the basic purposes of the 1977 Amendments, that is, encouraging the use of higher sulfur coals.

Full Versus Partial Control

In September 1978, the Administrator proposed a full or uniform control alternative and set forth other partial or variable control options as well for public comment. At that time, the Administrator made it clear that a decision as to the form of the final standard would not be made until the public comments were evaluated and additional analyses were completed. The analytical results are discussed later under Regulatory Analysis.

This issue focuses on whether power plants firing lower-sulfur coals should be required to achieve the same percentage reduction in potential SO_2 emissions as those burning higher-sulfur coals. When addressing this issue, the public commenters relied heavily on the statutory language and legislative history of Section 111 of the Clean Air Act Amendments of 1977 to bolster their arguments. Particular attention was directed to the Conference Report which says in the pertinent part:

> In establishing a national percent reduction for new fossil fuel-fired sources, the conferees agreed that the Administrator may, in his discretion, set a range of pollutant reduction that reflects varying fuel characteristics. Any departure from the uniform national percentage reduction requirement, however, must be accompanied by a finding that such a departure does not undermine the basic purposes of the House provision and other provisions of the act, such as maximizing the use of locally available fuels.

Comments Favoring Full or Uniform Control. Commenters in favor of full control relied heavily on the statutory presumption in favor of a uniform application of the percentage reduction requirement. They argued that the Conference Report language, ". . . the Administrator may, in his discretion, set a range of pollutant reduction that reflects varying fuel characteristics. . . ." merely reflects the contention of certain conferees that low-sulfur coals may be more difficult to treat than high-sulfur coals. This contention, they assert, is not borne out by EPA's technical documentation nor by utility applications for prevention of significant deterioration permits which clearly show that high removal efficiencies can be attained on low-sulfur coals. In the face of this, they maintain there is no basis for applying a lower percent reduction for such coals.

These commenters further maintain that a uniform application of the percent reduction requirement is needed to protect pristine areas and national parks, particularly in the West. In doing so, they note that emissions may be up to seven times higher at the individual plant level under a partial approach than under uniform control. In the face of this, they maintain that partial control cannot be considered to reflect best available control technology. They also contend that the adoption of a partial approach may serve to undermine the more stringent State requirements currently in place in the West.

Turning to national impacts, commenters favoring a uniform approach note that it will result in lower emissions. They maintain that these lower emissions are significant in terms of public health and that such reductions should be maximized, particularly in light of the Nation's commitment to greater coal use. They also assert that a uniform standard is clearly affordable. They point out that the incremental increase in costs associated with a uniform standard is small when compared to total utility expenditures and will have a minimal impact at the consumer level. They further maintain that EPA has inflated the costs of scrubber technology and has failed to consider factors that should result in lower costs in future years.

With respect to the oil impacts associated with a uniform standard, these same commenters are critical of the oil prices used in the EPA analyses and add that if a higher oil price had been assumed the supposed oil impact would not have materialized.

They also maintain that the adoption of a partial approach would serve to perpetuate the advantage that areas producing low-sulfur coal enjoyed under the current standard, which would be counter to one of the basic purposes of the House bill. On the other hand, they argue, a uniform standard would not only reduce the movement of low-sulfur coals eastward but would serve to maximize the use of local high-sulfur coals.

Finally, one of the commenters specified a more stringent full control option than had been analyzed by EPA. It called for a 95 percent reduction in potential SO_2 emissions with about a 280 ng/J (0.65 lb/million Btu) emission limit on a monthly basis. In addition, this alternative reflected higher oil prices and declining scrubber costs with time. The results were presented at the December 12 and 13 public hearing on the proposed standards.

Comments Favoring Partial or Variable Control. Those commenters advocating a partial or variable approach focused their arguments on the statutory language of Section 111. They maintained that the standard must be based on the "best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." They also asserted that the Conference Report language clearly gives the Administrator authority to establish a variable standard based on varying fuel characteristics, i.e., coal sulfur content.

Their principal argument is that a variable approach would achieve virtually the same emission reductions at the national level as a uniform approach but at substantially lower costs and without incurring a significant oil penalty. In view of this, they maintain that a variable approach best satisfies the statutory language of Section 111.

In support of variable control they also note that the revised NSPS will serve as a minimum requirement for prevention of significant deterioration and non-attainment considerations, and that ample authority exists to impose more stringent requirements on a case-by-case basis. They contend that these authorities should be sufficient to protect pristine areas and national parks in the West and to assure the attainment and maintenance of the health-related ambient air quality standards. Finally, they note that the NSPS is technology-based and not directly related to protection of the Nation's public health.

In addition, they argue that a variable control option would provide a better opportunity for the development of innovative technologies. Several commenters noted that, in particular, a uniform requirement would not provide an opportunity for the development of dry SO_2 control systems which they felt held considerable promise for bringing about SO_2 emission reductions at lower costs and in a more reliable manner.

Commenters favoring variable control also advanced the arguments that a standard based on a range of percent reductions would provide needed flexibility, particularly when selecting intermediate sulfur content coals. Further, if a control system failed to meet design expectations, a variable approach would allow a source to move to lower-sulfur coal to achieve compliance. In addition, for low-sulfur coal applications, a variable option would substantially reduce the energy penalty of operating wet scrubbers since a portion of the flue gas could be used for plume reheat.

To support their advocacy of a variable approach, two commenters, the Department of Energy and the Utility Air Regulatory Group (UARG, representing a number of utilities), presented detailed results of analyses that had been conducted for them. UARG analyzed a standard that required a minimum reduction of 20 percent with 520 ng/J (1.20 lb/million Btu) monthly emission limit. The Department of Energy specified a partial control option that required a 33 percent minimum requirement with a 430 ng/J (1.0 lb/million Btu) monthly emission limit.

Faced with these comments, the Administrator determined the final analyses that should be performed. He concluded that analyses should be conducted on a range of alternative emission limits and percent reduction requirements in order to determine the approach which best satisfies the statutory language and legislative history of section 111. For these analyses, the Administrator specified a uniform or full control option, a partial control option reflecting the Department of Energy's recommendation for a 33 percent minimum control requirement, and a variable control option which specified a 520 ng/J (1.20 lb/million Btu) emission limitation with a 90 percent reduction in potential SO_2 emissions except when emissions to the atmosphere were reduced below 260 ng/J (0.60 lb/million Btu), when only a 70 percent reduction in potential SO_2 emissions would apply. Under the variable approach, plants firing high-sulfur coals would be required to achieve a 90 percent reduction in potential emissions in order to comply with the emission limitation. Those using intermediate and low-sulfur content coals would be permitted to achieve between 70 and 90 percent, provided their emissions were less than 260 ng/J (0.60 lb/million BTU).

In rejecting the minimum requirement of 20 percent advocated by UARG, the Administrator found that it not only resulted in the highest emissions, but that it was also the least cost effective of the variable control options considered. The more stringent full control option presented in the comments was rejected because it required a 95 percent reduction in potential emissions which may not be within the capabilities of demonstrated technology for high-sulfur coals in all cases.

Emergency Conditions

The final standards allow an owner or operator to bypass uncontrolled flue gases around a malfunctioning FGD system provided (1) the FGD system has been constructed with a spare FGD module, (2) FGD modules are not available in sufficent numbers to treat the entire quantity of flue gas generated, and (3) all available electric generating capacity is being utilized in a power pool or network consisting of the generating capacity of the affected utility company (except for the capacity of the largest single generating unit in the company), and the amount of power that could be purchased from neighboring interconnected utility companies. The final standards are essentially the same as those proposed. The revisions involve wording changes to clarify the Administrator's intent and revisions to address potential load management and operating problems. None of the comments received by EPA disputed the need for the emergency condition provisions or objected to their intent.

The intent of the final standards is to encourage power plant owners and operators to install the best available FGD systems and to implement effective operation and maintenance procedures but not to create power supply disruptions. FGD systems with spare FGD modules and FGD modules with spare equipment components have greater capability of reliable operation than systems without spares. Effective control and operation of FGD systems by engineering supervisory personnel experienced in chemical process operations and properly trained FGD system operators and maintenance staff are also important in attaining reliable FGD system operation. While the standards do not require these equipment and staffing features, the Administrator believes that their use will make compliance with the standards easier. Malfunctioning FGD systems are not exempt from the SO_2 standards except during infrequent power supply emergency periods. Since the exemption does not apply unless a spare module has been installed (and operated), a spare module is required for the exemption to apply. Because of the disproportionate cost of installing a spare module on steam generators having a generating capacity of 125 MW or less, the standards do not require them to have spare modules before the emergency conditions exemption applies.

The proposed standards included the requirement that the emergency condition exemption apply only to those facilities which have installed a spare FGD system module or which have 125 MW or less of output capacity. However, they did not contain procedures for demonstrating spare module capability. This capability can be easily determined once the facility commences operation. To specify how this determination is to be performed, provisions have been added to the regulations. This determination is not required unless the owner or operator of the affected facility wishes to claim spare module capability for the purpose of availing himself of the emergency condition exemption. Should the Administrator require a demonstration of spare module capability, the owner or operator would schedule a test within 60 days for any period of operation lasting from 24 hours to 30 days to demonstrate that he can attain the appropriate SO_2 emission control requirements when the facility is operated at a maximum rate without using one of its FGD system modules. The test can start at any time of day and modules may be rotated in and out of service, but at all times in the test period one module (but not necessarily the same module) must not be operated to demonstrate spare module capability.

Although it is within the Administrator's discrétion to require the spare module capability demonstration test, the owner or operator of the facility has the option to schedule the specific date and duration of the test. A minimum of only 24 hours of operation are required during the test period because this period of time is adequate to demonstrate spare module capability and it may be unreasonable in all circumstances to require a longer (e.g., 30 days) period of operation at the facility's maximum heat input rate. Because the owner or operator has the flexibility to schedule the test, 24 hours of operation at maximum rate will not impose a significant burden on the facility

The Administrator believes that the standards will not cause supply disruption because (1) well designed and operated FGD systems can attain high operating availability, (2) a spare FGD module can be used to rotate other modules out of service for periodic maintenance or to replace a malfunctioning module, (3) load shifting of electric generation to another generating unit can normally be used if a part or all of the FGD system were to malfunction, and (4) during abnormal power supply emergency periods, the bypassing exemption ensures that the regulations would not require a unit to stand idle if its operation were needed to protect the reliability of electric service. The Administrator believes that this exemption will not result in extensive bypassing because the probability of a major FGD malfunction and power supply emergency occurring simultaneously is small.

A commenter asked that the definition of system capacity be revised to ensure that the plant's capability rather than plant rated capacity be used because the full rated capacity is not always operable. The Administrator agrees with this comment because a component failure (e.g., the failure of one coal pulverizer) could prevent a boiler from being operated at its rated capacity, but would not cause the unit to be entirely shut down. The definition has been revised to allow use of the plant's capability when determining the net system capacity.

One commenter asked that the definition of system capacity be revised to include firm contractual purchases and to exclude firm contractual sales. Because power obtained through contractual purchases helps to satisfy load demand and power sold under contract affects the net electric generating capacity available in the system, the Administrator agrees with this request and has included power purchases in the definition of net system capacity and has excluded sales by adding them to the definition of system load.

A commenter asked that the ownership basis for proration of electric capacity in several definitions be modified when there are other contractual arrangements. The Administrator agrees with this comment and has revised the definitions accordingly.

One commenter asked that definitions describing "all electric generating equipment owned by the utility company" specifically include hydroelectric plants. The proposed definitions did include these plants, but the Administrator agrees with the clarification requested, and the definitions have been revised.

A commenter asked that the word "steam" be removed from the definition of system emergency reserves to clarify that nuclear units are included. The Administrator agrees with the comment and has revised the definition.

Several commenters asked that some type of modification be made to the emergency condition provisions that would consider projected system load increases within the next calendar day. One commenter asked that emergency conditions apply based on a projection of the next day's load. The Administrator does not agree with the suggestion of using a projected load, which may or may not materialize, as a criterion to allow bypassing of SO_2 emissions, because the load on a generating unit with a malfunctioning FGD system should be reduced whenever there is other available system capacity.

A commenter recommended that a unit removed from service be allowed to return to service if such action were necessary to maintain or reestablish system emergency reserves. The Administrator agrees that it would be impractical to take a large steam generating unit entirely out of service whenever load demand is expected to later increase to the level where there would be no other unit available to meet the demand or to maintain system emergency reserves. To address the problem of reducing load and later returning the load to the unit, the Administrator has revised the proposed emergency condition provisions to give an owner or operator of a unit with a malfunctioning FGD system the option of keeping (or bringing) the unit into spinning reserve when the unit is needed to maintain (or reestablish) system emergency reserves. During this period, emissions must be controlled to the extent that capability exists within the FGD system, but bypassing emissions would be allowed when the capability of a partially or completely failed FGD system is inadequate. This procedure will allow the unit to operate in spinning reserve rather than being entirely shut down and will ensure that a unit can be quickly restored to service. The final emergency condition provisions permit bypassing of emissions from a unit kept in spinning reserve, but only (1) when the unit is the last one available for maintaining system emergency reserves, (2) when it is operated at the minimum load consistent with keeping the unit in spinning reserve, and (3) has inadequate operational FGD capability at the minimum load to completely control SO_2 emissions. This revision will still normally require load on a malfunctioning unit to be reduced to a minimum level, even if load demand is anticipated to increase later; but it does prevent having to take the unit entirely out of operation and keep it available in spinning reserve to assume load should an emergency arise or as load increases the following day. Because emergency condition periods are a small percentage of total operating hours, this revision to allow bypassing of SO_2 emissions from a unit held in spinning reserve with reduced output is expected to have minor impact on the amount of SO_2 emitted.

One commenter stated that the proposed provisions would not reduce the necessity for additional plant capacity to compensate for lower net reliability. The Administrator does not agree with this comment because the emergency condition provisions allow operation of a unit with a failed FGD system whenever no other generating capacity is available for operation and thereby protects the reliability of electric service. When electric load is shifted from a new steam-electric generating unit to another electric generating unit, there would be no net change in reserves within the power system. Thus, the emergency condition provisions prevent a failed FGD system from impacting upon the utility company's ability to generate electric power and prevents an impact upon reserves needed by the power system to maintain reliable electric service.

A commenter asked that the definition of available system capacity be clarified because (1) some utilities have certain localized areas or zones that, because of system operating parameters, cannot be served by all of the electric generating units which constitute the utility's system capacity, and (2) an affected facility may be the only source of supply for a zone or area. Almost all electric utility generating units in the United States are electrically interconnected through power transmission lines and switching stations. A few isolated units in the U.S. are not interconnected to at least one other electric generating unit and it is possible that a new unit could also be constructed in an isolated area where interconnections would not be practical. For a single, isolated unit where it is not practical to construct interconnections, the emergency condition provisions would apply whenever an FGD malfunction occurred because there would be no other available system capacity to which load could be shifted. It is also possible that two or three units could be interconnected, but not interconnected with a larger power network (e.g., Alaska and Hawaii). To clarify this situation, the definitions of net system capacity, system load, and system emergency reserves have been revised to include only that electric power or capacity interconnected by a network of power transmission facilities. Few units will not be interconnected into a network encompassing the principal and neighboring utility companies. Power plants, including those without FGD systems, are expected to experience electric generating malfunctions and power systems are planned with reserve generating capacity and interconnecting electric transmission lines to provide means of obtaining electricity from alternative generating facilities to meet demand when these occasions arise. Arrangements for an affected facility would typically include an interconnection to a power transmission network even when it is geographically located away from the bulk of the utility company's power system to allow purchase of power from a neighboring utility for those localized service areas when necessary to maintain service reliability. Contract arrangements can provide for trades of power in which a localized zone served by the principal company owning or operating the affected facility is supplied by a neighboring company. The power bought by the principal company can, if desired by the neighboring company, be replaced by operation of other available units in the principal company even if these units are located at a distance from the localized service zone. The proposed definition of emergency condition was contingent upon the purchase of power from another electrical generation facility. To further clarify this relationship, the Administrator has revised the proposed definitions to define the relationship between the principal company (the utility company that owns the generating unit with the malfunctioning FGD system) and the neighboring power companies for the purpose of determining when emergency conditions exist.

A commenter requested that the proposed compliance provisions be revised so that they could not be interpreted to force a utility to operate a partially functional FGD module when extensive damage to the FGD module would occur. For example, a severely vibrating fan must be shut down to prevent damage even though the FGD system may be otherwise functional. The Administrator agrees with this comment and has revised the compliance provisions not to require FGD operation when significant damage to equipment would result.

One commenter asked that the definition of system emergency reserves account for not only the capacity of the single largest generating unit, but also for reserves needed for system load-frequency regulation. Regulation of power frequency can be a problem when the mix of capacitive and reactive loads shift. For example, at night capacitive load of industrial plants can adversely affect power factors. The Administrator disagrees that additional capacity should be kept independent of the load shifting requirements. Under the definition for system emergency reserves, capacity equivalent to the largest single unit in the system was set aside for load management. If frequency regulation has been a particular problem, extra reserve margins would have been maintained by the utility company even if an FGD system were not installed. Reserve capacity need not be maintained within a single generating unit. The utility company can regulate system load-frequency by distributing their system reserves throughout the electric power system as needed. In the Administrator's judgment, these regulations do not impact upon the reserves maintained by the utility company for the purpose of maintaining power system integrity, because the emergency condition provisions do not restrict the utility company's freedom in distributing their reserves and do not require construction of additional reserves.

A commenter asked that utility operators be given the option to ignore the loss of SO_2 removal efficiency due to FGD malfunctions by reducing the level of electric generation from an affected unit. This would control the amount of

SO_2 emitted on a pounds per hour basis, but would also allow and exemption from the percentage of SO_2 removal specified by the SO_2 standards. The Administrator believes that allowing this exemption is not necessary because load can usually be shifted to other electric generating units. This procedure provides an incentive to the owner or operator to properly maintain and operate FGD systems. Under the procedures suggested by the commenter, neglect of the FGD system would be encouraged because an exemption would allow routine operation at reduced percentages of SO_2 removal. Steam generating units are often operated at less than rated capacity and a fully operational FGD system would not be required for compliance during these periods if this exemption were allowed. The procedure suggested by the commenter is also not necessary because FGD modules can be designed and constructed with separate equipment components so that they are routinely capable of independent operation whenever another module of the steam generating unit's FGD system is not available. Thus, reducing the level of electric generation and removing the failed FGD module for servicing would not affect the remainder of the FGD system and would permit the utility to maintain compliance with the standards without having to take the generating unit entirely out of operation. Each module should have the capability of attaining the same percentage reduction of SO_2 from the flue gas it treats regardless of the operability of the other modules in the system to maintain compliance with the standards. Although the efficiency of more than one FGD module may occasionally be affected by certain equipment malfunctions, a properly designed FGD system has no routine need for an exemption from the SO_2 percentage reduction requirement when the unit is operated at reduced load. The Administrator has concluded that the final regulations provide sufficient flexibility for addressing FGD malfunctions and that an exemption from the percentage SO_2 removal requirement is not necessary to protect electric service reliability or to maintain compliance with these SO_2 standards.

Particulate Matter Standard

The final standard limits particulate matter emissions to 13 ng/J (0.03 lb/million Btu) heat input and is based on the application of ESP or baghouse control technology. The final standard is the same as the proposed. The Administrator has concluded that ESP and baghouse control systems are the best demonstrated systems of continuous emission reduction (taking into consideration the cost of achieving such emission reduction, and nonair quality health and enviornmental impacts, and energy requirements) and that 13 ng/J (0.03 lb/million Btu) heat input represents the emission level achievable through the application of these control systems.

One group of commenters indicated that they did not support the proposed standard because in their opinion it would be too expensive for the benefits obtained; and they suggested that the final standard limit emissions to 43 ng/J (0.10 lb/million Btu) heat input which is the same as the current standard under 40 CFR Part 60 Subpart D. The Administrator disagrees with the commenters because the available data clearly indicate that ESP and baghouse control systems are capable of performing at the 13 ng/J (0.03 lb/million Btu) heat input emission level, and the economic impact evaluation indicates that the costs and economic impacts of installing these systems are reasonable.

The number of commenters expressed the opinion that the proposed standard was to strict, particularly for power plants firing low-sulfur coal, because baghouse control systems have not been adequately demonstrated on full-size power plants. The commenters suggested that extrapolation of test data from small scale baghhouse control systems, such as those used to support the proposed standard, to full-size utility applications is not reasonable.

The Administrator believes that baghouse control systems are demonstrated for all sizes of power plants. At the time the standards were proposed, the Administrator concluded that since baghouses are designed and constructed in modules rather than as one large unit, there should be no technological barriers to designing and constructing utility-sized facilities. The largest baghouse-controlled, coal-fired power plant for which EPA had emission test data to support the proposed standard was 44 MW. Since the standards were proposed, additional information has become available which supports the Administrator's position that baghouses are demonstrated for all sizes of power plants. Two large baghouse-controlled, coal-fired power plants have recently initiated operations. EPA has obtained emission data for one of these units. This unit has achieved particulate matter emission levels below 13 ng/J (0.03 lb/million Btu) heat input. The baghouse system for this facility has 28 modules rated at 12.5 MW capacity per module. This supports the Administrator's conclusion that baghouses are designed and constructed in modules rather than as one large unit, and there should be no technological barriers to designing and constructing utility-sized facilities.

One commenter indicated that baghouse control systems are not demonstrated for large utility application at this time and recommended that EPA gather one year of data from 1000 MW of baghouse installations to demonstrate that baghouses can operate reliably and achieve 13 ng/J (0.03 lb/million Btu) heat input. The standard would remain at 21 to 34 ng/J (0.05 to 0.08 lb/million Btu) heat input until such demonstration. The Administrator does not believe this approach is necessary because baghouse control systems have been adequately demonstrated for large utility applications.

One group of commenters supported the proposed standard of 13 ng/J (0.03 lb/million Btu) heat input. They indicated that in their opinion the proposed standard attained the proper balance of cost, energy and environmental factors and was necessary in consideration of expected growth in coal-fired power plant capacity.

Another group of commenters which included the trade association of emission control system manufacturers indicated that 13 ng/J (0.03 lb/million Btu) is technically achievable. The trade association further indicated the proposed standard is technically achievable for either high- or low-sulfur coals, through the use of baghouses, ESPs, or wet scrubbers.

A number of commenters recommended that the proposed standard be lowered to 4 ng/J (0.01 lb/million Btu) heat input. This group of commenters presented additional emission data for utility baghouse control systems to support their recommendation. The data submitted by the commenters were not available at the time of proposal and were for utility units of less than 100 MW electrical output capacity. The commenters suggested that a 4 ng/J (0.01 lb/million Btu) heat input standard is achievable based on baghouse technology, and they suggested that a standard based on baghouse technology would be consistent with the technology-forcing nature of section 111 of the Act. The Administrator believes that the available data base for baghouse performance supports a standard of 13 ng/J (0.03 lb/million Btu) heat input but does not support a lower standard such as 4 ng/J (0.01 lb/million Btu) heat input.

One commenter suggested that the standard should be set at 26 ng/J (0.06 lb/million Btu) heat imput so that particulate matter control systems would not be necessary for oil-fired utility steam generators. Although it is expected that few oil-fired utility boilers will be constructed, the ESP performance data which is contained in the "Electric Utility Steam Generating Units, Background Information for Promulgated Emission Standards" (EPA 450/3-79-021), supports the conclusion that ESPs are applicable to both oil firing and coal firing. The Administrator believes that emissions from oil-fired utility boilers should be controlled to the same level as coal-fired boilers.

NO_x Standard

The NO_x standards limit emissions to 210 ng/J (0.50 lb/million Btu) heat input from the combustion of subbituminous coal and 260 ng/J (0.60 lb/million Btu) heat imput from the combustion of bituminous coal, based on a 30-day rolling average. In addition, emission limits have been established for other solid, liquid, and gaseous fuels, as discussed in the rational section of this preamble. The final standards differ from the proposed standards only in that the final averaging time for determining compliance with the standards is based on a 30-day rolling average, whereas a 24-hour average was proposed. All comments received during the public comment period were considered in developing the final NO_x standards. The major issues raised during the comment period are discussed below.

One issue concerned the possibility that the proposed 24-hour averaging period for coal might seriously restrict the flexibility boiler operators need during day-to-day operation. For example, several commenters noted that on some boilers the control of boiler tube slagging may periodically require increased excess air levels, which, in turn, would increase NO_x emissions. One commenter submitted data indicating that two modern Combustion Engineering (CE) boilers at the Colstrip, Montana plant of the Montana Power Company do not consistently achieve the proposed NO_x level of 210 ng/J (0.50 lb/million Btu) heat input on a 24-hour basis. The Colstrip boilers burn subbituminous coal and are required to comply with the NO_x standard under 40 CFR Part 60, Subpart D of 300 ng/J (0.70 lb/million Btu) heat input. Several other commenters recommended that the 24-hour averaging period be extended to 30 days to allow for greater operational flexibility.

As an aid in evaluating the operational flexibility question, the Administrator has reviewed a total of 24 months of continuously monitored NO_x data from the two Colstrip boilers. Six months of these data were available to the Administrator before proposal of these standards, and two months were submitted by a commenter. The commenter also submitted a summary of 28 months of Colstrip data indicating the number of 24-hour averages per month above 210 ng/J (0.50 lb/million Btu) heat input. The remaining Colstrip data were obtained by the Administrator from the State of Montana after proposal. In addition to the Colstrip data, the Administrator has reviewed approximately 10 months of continuously monitored NO_x data from five modern CE utility boilers. Three of the boilers burn subbituminous coal, two burn bituminous coal, and all five have monitors that have passed certification tests. These data were obtained from electric utility companies after proposal. A summary of all of the continuously monitored NO_x data that the Administrator has considered appears in "Electric Utility Steam Generating Units, Background Information for Promulgated Emission Standards" (EPA 450/3-79-021).

The usefulness of these continuously monitored data in evaluating the ability of modern utility boilers to continuously achieve the NO_x emission limits of 210 and 260 ng/J (0.50 and 0.60 lb/million Btu) heat input is somewhat limited. This is because the boilers were required to comply with a higher NO_x level of 300 ng/J (0.70 lb/million Btu) heat input. Nevertheless some conclusions can be drawn, as follows:

(1) Nearly all of the continuously monitored NO_x data are in compliance with the boiler design limit of 300 ng/J (0.70 lb/million Btu) heat input on the basis of a 24-hour average.

(2) Most of the continuously monitored NO_x data would be in compliance with limits of 260 ng/J (0.60 lb/million Btu) heat input for bituminous coal ov 210 ng/J (0.50 lb/million Btu) heat input for subbituminous coal when averaged over a 30-day period. Some of the data would be out of compliance based on a 24-hour average.

(3) The volume of continuously monitored NO_x emission data evaluated by the Administrator (34 months from seven large coal-fired boilers) is sufficient to indicate the emission variability expected during day-to-day operation of a utility-size boiler. In the Administrator's judgment, this emission variability adequately represents slagging conditions, coal variability, load changes, and other factors that may influence the level of NO_x emissions.

(4) The variability of continuously monitored NO_x data is sufficient to cause some concern over the ability of a utility boiler that burns solid fuel to consistently achieve a NO_x boiler design limit, whether 300, 260, or 210 ng/J (0.70, 0.60, or 0.50 lb/million Btu) heat input, based on 24-hour averages. In contrast, it appears that there would be no difficulty in achieving the boiler design limit based on 30-day periods.

Based on these conclusions, the Administrator has decided to require compliance with the final standards for solid fuels to be based on a 30-day rolling average. The Administrator believes that the 30-day rolling average will allow boilers made by all four major boiler manufacturers to achieve the standards while giving boiler operators the flexibility needed to handle conditions encountered during normal operation.

Although the Administrator has not evaluated continuously monitored NO_x data from boilers manufactured by companies other than CE, the data from CE boilers are considered representative of the other boiler manufacturers. This is because the boilers of all four manufacturers are capable of achieving the same NO_x design limit, and because the conditions that occur during normal operation of a boiler (e.g., slagging, variations in fuel quality, and load reductions) are similar for all four manufacturer designs. These conditions, the Administrator believes, lead to similar emission variability and require essentially the same degree of operational flexibility.

Some commenters have question the validity of the Colstrip data because the Colstrip continuous NO_x monitors have not passed certification tests. In April and June of 1978 EPA conducted a detailed evaluation of these monitors. The evaluation led the Administrator to conclude that the monitors were probably biased high, but by less than 21 ng/J (0.50 lb/million Btu) heat input. Since this error is so small (less than 10 percent), the Administrator considers the data appropriate to use in developing the standards.

A number of commenters expressed concern over the ability of as many as three of the four major boiler manufacturer designs to achieve the proposed standards. Although most of the available NO_x test data are from CE boilers, the Administrator believes that all four of the boiler manufacturers will be able to supply boilers capable of achieving the standards. This conclusion is supported with (1) emission test results from 14 CE, seven Babcock and Wilcox (B&W), three Foster Wheeler (FW), and four Riley Stoker (RS) utility boilers; (2) 34 months of continuously monitored NO_x emission data from seven CE boilers; and (3) an evaluation of plans under way at B&W, FW, and RS to develop low-emission burners and furnace designs. Full-scale tests of these burners and furnace designs have proven their effectiveness in reducing NO_x emissions without apparent long-term adverse side effects.

Another issue raised by commenters concerned the effect that variations in the nitrogen content of coal may have on achieving the NO_x standards. The Adminstrator recognizes that NO_x levels are sensitive to the nitrogen content of the coal burned and that the combustion of high-nitrogen-content coals might be expected to result in higher NO_x emissions than those from coals with low nitrogen contents. However, the Administrator also recognizes that other factors contribute to NO_x levels, including moisture in the coal, boiler design, and boiler operating practice. In the Administrator's judgment, the emission limits for NO_x are achievable with properly designed and operated boilers burning any coal, regardless of its nitrogen content. As evidence of this, three of the six boilers tested by EPA burned coals with nitrogen contents above average, and yet exhibited NO_x emission levels well below the standards. The three boilers that burned coals with lower nitrogen contents also exhibited emission levels below the standards. The Administrator believes this is evidence that at NO_x levels near 210 and 260 ng/J (0.50 and 0.60 lb/million Btu) heat input, factors other than fuel-nitrogen-content predominate in determining final emission levels.

A number of commenters expressed concern over the potential for accelerated tube wastage (i.e., corrosion) during operation of a boiler in compliance with the proposed standards. Almost all of the 300-hour and 30-day coupon corrosion tests conducted during the EPA-sponsored low-NO_x studies indicate that corrosion rates decrease or remain stable during operation of boilers at NO_x levels as low as those required by the standards. In the few instances where corrosion rates increased during low-NO_x operation, the increases were considered minor. Also, CE has guaranteed that its new boilers will achieve the NO_x emission limits without increased tube corrosion rates. Another boiler manufacturer, B&W, has developed new low-emission burners that minimize corrosion by surrounding the flame in an oxygen-rich atmosphere. The other boiler manufacturers have also developed techniques to reduce the potential for corrosion during low-NO_x operation. The Administrator has received no contrasting information to the effect that boiler tube corrosion rates would significantly increase as a result of compliance with the standards.

Several commenters stated that according to a survey of utility boilers subject to the 300 ng/J (0.70 lb/million Btu) heat input standard under 40 CFR Part 60, Subpart D, none of the boilers can achieve the standard promulgated here of 260 ng/J (0.60 lb/million Btu) heat input on a range of bituminous coals. Three of the six utility boilers tested by EPA burned bituminous coal. (Two of these boilers were manufactured by CE and one by B&W.) In addition, the Administrator has reviewed continuously monitored NO_x data from two CE boilers that burn bituminous coal. Finally, the Administrator has examined NO_x emission data obtained by the boiler manufacturers on seven CE, four B&W, three FW, and three RS modern boilers, all of which burn bituminous coal. Nearly all of these data are below the 260 ng/J (0.60 lb/million Btu) heat input standard. The Administrator believes that these data provide adequate evidence that the final NO_x standard for bituminous coal is achievable by all four boiler manufacturer designs.

An issue raised by several commenters concerned the use of catalytic ammonia injection and advanced low-emission burners to achieve NO_x emission levels as low as 15 ng/J (0.034 lb/million Btu) heat input. Since these controls are not yet available, the commenters recommended that new utility boilers be designed with sufficient space to allow for the installation of ammonia injection and advanced burners in the future. In the meantime the commenters recommended that NO_x emissions be limited to 190 ng/J (0.45 lb/million Btu) heat input. The Administrator believes that the technology needed to achieve NO_x levels as low as 15 ng/J (0.034 lb/million Btu) heat input has not been adequately demonstrated at this time. Although a pilot-scale catalytic-ammonia-injection system has successfully achieved 90 percent NO_x removal at a coal-fired utility power plant in Japan, operation of a full-scale ammonia-injection system has not yet been demonstrated on a large coal-fired boiler. Since the Clean Air Act requires that emission control technology for new source performance standards be adequately demonstrated, the Administrator cannot justify establishing a low NO_x standard based on unproven technology. Similarly, the Administrator cannot justify requiring boiler designs to provide for possible future installation of unproven technology.

The recommendation that NO_x emissions be limited to 190 ng/J (0.45 lb/million Btu) heat input is based on boiler manufacturer guarantees in California. (No such utility boilers have been built as yet.) Although manufacturer guarantees are appropriate to consider when establishing emission limits, they cannot always be used as a basis for a standard. As several commenters have noted, manufacturers do not always achieve their performance guarantees. The standard is not established at this level, because emission test data are not available which demonstrate that a level of 190 ng/J (0.45 lb/million Btu) heat input can be continuously achieved without adverse side effects when a wide variety of coals are burned.

Regulatory Analysis

Executive Order 12044 (March 24, 1978), whose objective is to improve Government regulations, requires executive branch agencies to prepare regulatory analyses for regulations that may have major economic consequences. EPA has extensively analyzed the costs and other impacts of these regulations. These analyses, which meet the criteria for preparation of a regulatory analysis, are contained within the preamble to the proposed regulations (43 FR 42154), the background documentation made available to the public at the time of proposal (see STUDIES, 43 FR 42171), this preamble, and the additional background information document accompanying this action ("Electric Utility Steam Generating Units, Background Information for Promulgated Emission Standards," EPA-450/3-79-021). Due to the volume of this material and its continual development over a period of 2-3 years, it is not practical to consolidate all analyses into a single document. The following discussion gives a summary of the most significant alternatives considered. The rationale for the action taken for each pollutant being regulated is given in a previous section.

In order to determine the appropriate form and level of control for the standards, EPA has performed extensive analysis of the potential national impacts associated with the alternative standards. EPA employed economic models to forecast the structure and operating characteristics of the utility industry in future years. These models project the environmental, economic, and energy impacts of alternative standards for the electric utility industry. The major analytical efforts took place in three phases as described below.

Phase 1. The initial effort comprised a preliminary analysis completed in April 1978 and a revised assessment completed in August 1978. These analyses were presented in the September 19, 1978 **Federal Register** proposal (43 FR 42154). Corrections to the September proposal package and additional information was published on November 27, 1978 (43 FR 55258). Further details of the analyses can be found in "Background Information for Proposed SO_2 Emission Standards—Supplement," EPA 450/2-78-007a-1.

Phase 2. Following the September 19 proposal, the EPA staff conducted additional analysis of the economic, environmental, and energy impacts associated with various alternative sulfur dioxide standards. As part of this effort, the EPA staff met with representatives of the Department of Energy, Council of Economic Advisors, Council on Wage and Price Stability, and others for the purpose of reexamining the assumptions used for the August analysis and to develop alternative forms of the standard for analysis. As a result, certain assumptions were changed and a number of new regulatory alternatives were defined. The EPA staff again employed the economic model that was used in August to project the national and regional impacts associated with each alternative considered.

The results of the phase 2 analysis were presented and discussed at the public hearings in December and were published in the **Federal Register** on December 8, 1978 (43 FR 7834).

Phase 3. Following the public hearings, the EPA staff continued to analyze the impacts of alternative sulfur dioxide standards. There were two primary reasons for the continuing analysis. First, the detailed analysis (separate from the economic modeling) of regional coal production impacts pointed to a need to investigate a range of higher emission limits.

Secondly, several comments were received from the public regarding the potential of dry sulfur dioxide scrubbing systems. The phase 1 and phase 2 analyses had assumed that utilities would use wet scrubbers only. Since dry scrubbing costs substantially less then wet scrubbing, adoption of the dry technology would substantially change the economic, energy, and environmental impacts of alternative sulfur dioxide standards. Hence, the phase 3 analysis focused on the impacts of alternative standards under a range of emission ceilings assuming both wet technology and the adoption of dry scrubbing for applications in which it is technically and economically feasible.

Impacts Analyzed

The environmental impacts of the alternative standards were examined by projecting pollutant emissions. The emissions were estimated nationally and by geographic region for each plant type, fuel type, and age category. The EPA staff also evaluated the waste products that would be generated under alternative standards.

The economic and financial effects of the alternatives were examined. This assessment included an estimation of the utility capital expenditures for new plant and pollution control equipment as well as the fuel costs and operating and maintenance expenses associated with the plant and equipment. These costs were examined in terms of annualized costs and annual revenue requirements. The impact on consumers was determined by analyzing the effect of the alternatives on average consumer costs and residential electric bills. The alternatives were also examined in terms of cost per ton of SO_2 removal. Finally, the present value costs of the alternatives were calculated.

The effects of the alternative proposals on energy production and consumption were also analyzed. National coal use was projected and broken down in terms of production and consumption by geographic region. The amount of western coal shipped to the Midwest and East was also estimated. In addition, utility consumption of oil and natural gas was analyzed.

Major Assumptions

Two types of assumptions have an important effect on the results of the analyses. The first group involves the model structure and characteristics. The second group includes the assumptions used to specify future economic conditions.

The utility model selected for this analysis can be characterized as a cost minimizing economic model. In meeting demand, it determines the most economic mix of plant capacity and electric generation for the utility system, based on a consideration of construction and operating costs for new plants and variable costs for existing plants. It also determines the optimum operating level for new and existing plants. This economic-based decision criteria should be kept in mind when analyzing the model results. These criteria imply, for example, that all utilities base decisions on lowest costs and that neutral risk is associated with alternative choices.

Such assumptions may not represent the utility decision making process in all cases. For example, the model assumes that a utility bases supply decisions on the cost of constructing and operating new capacity versus the cost of operating existing capacity. Environmentally, this implies a tradeoff between emissions from new and old sources. The cost minimization assumption implies that in meeting the standard a new power plant will fully scrub high-sulfur coal if this option is cheaper than fully or partially scrubbing low-sulfur coal. Often the model will have to make such a decision, especially in the Midwest where utilities can choose between burning local high-sulfur or imported western low-sulfur coal. The assumption of risk neutrality implies that a utility will always choose the low-cost option. Utilities, however, may perceive full scrubbing as involving more risks and pay a premium to be able to partially scrub the coal. On the other hand, they may perceive risks associated with long-range transportation of coal, and thus opt for full control even though partial control is less costly.

The assumptions used in the analyses to represent economic conditions in a given year have a significant impact on the final results reached. The major assumptions used in the analyses are shown in Table 1 and the significance of these parameters is summarized below.

The growth rate in demand for electric power is very important since this rate determines the amount of new capacity which will be needed and thus directly affects the emission estimates and the projections of pollution control costs. A high electric demand growth rate results in a larger emission reduction associated with the proposed standards and also results in higher costs.

The nuclear capacity assumed to be installed in a given year is also important to the analysis. Because nuclear power is less expensive, the model will predict construction of new nuclear plants rather than new coal plants. Hence, the nuclear capacity assumption affects the amount of new coal capacity which will be required to meet a given electric demand level. In practice, there are a number of constraints which limit the amount of nuclear capacity which can be constructed, but for this study, nuclear capacity was specified approximately equal to the moderate growth projections of the Department of Energy.

The oil price assumption has a major impact on the amount of predicted new coal capacity, emissions, and oil consumption. Since the model makes generation decisions based on cost, a low oil price relative to the cost of building and operating a new coal plant will result in more oil-fired generation and less coal utilization. This results in less new coal capacity which reduces capital costs but increases oil consumption and fuel costs because oil is more expensive per Btu than coal. This shift in capacity utilization also affects emissions, since an existing oil plant generally has a higher emission rate than a new coal plant even when only partial control is allowed on the new plant.

Coal transportation and mine labor rates both affect the delivered price of coal. The assumed transportation rate is generally more important to the predicted consumption of low-sulfur coal (relative to high-sulfur coal), since that is the coal type which is most often shipped long distances. The assumed mining labor cost is more important to eastern coal costs and production estimates since this coal production is generally much more labor intensive than western coal.

Because of the uncertainty involved in predicting future economic conditions, the Administrator anticipated a large number of comments from the public regarding the modeling assumptions. While the Administrator would have liked to analyze each scenario under a range of assumptions for each critical parameter, the number of modeling inputs made such an approach impractical. To decide on the best assumptions and to limit the number of sensitivity runs, a joint working group was formed. The group was comprised of representatives from the Department of Energy, Council of Economic Advisors, Council on Wage and Price Stability, and others. The group reviewed model results to date, identified the key inputs, specified the assumptions, and identified the critical parameters for which the degree of uncertainty was such that sensitivity analyses should be performed. Three months of study resulted in a number of changes which are reflected in Table 1 and discussed below. These assumptions were used in both the phase 2 and phase 3 analyses.

After more evaluation, the joint working group concluded that the oil prices assumed in the phase 1 analysis were too high. On the other hand, no firm guidance was available as to what oil prices should be used. In view of this, the working group decided that the best course of action was to use two sets of oil prices which reflect the best estimates of those governmental entities concerned with projecting oil prices. The oil price sensitivity analysis was part of the phase 2 analysis which was distributed at the public hearing. Further details are available in the draft report, "Still Further Analysis of Alternative New Source Performance Standards for New Coal-Fired Power Plants (docket number IV–A–5)." The analysis showed that while the variation in oil price affected the magnitude of emissions, costs, and energy impacts, price variation had little effect on the relative impacts of the various NSPS alternatives tested. Based on this conclusion, the higher oil price was selected for modeling purposes since it paralleled more closely the middle range projections by the Department of Energy.

Reassessment of the assumptions made in the phase 1 analysis also revealed that the impact of the coal washing credit had not been considered in the modeling analysis. Other credits allowed by the September proposal, such as sulfur removed by the pulverizers or in bottom ash and flyash, were determined not to be significant when viewed at the national and regional levels. The coal washing credit, on the other hand, was found to have a significant effect on predicted emissions levels and, therefore, was factored into the analysis.

As a result of this reassessment, refinements also were made in the fuel gas desulfurization (FGD) costs assumed. These refinements include changes in sludge disposal costs, energy penalties calculated for reheat, and module sizing. In addition, an error was corrected in the calculation of partial scrubbing costs. These changes have resulted in relatively higher partial scrubbing costs when compared to full scrubbing.

Changes were made in the FGD availability assumption also. The phase 1 analysis assumed 100 percent availability of FGD systems. This assumption, however, was in conflict with EPA's estimates on module availability. In view of this, several alternatives in the phase 2 analysis were modeled at lower system availabilities. The assumed availability was consistent with a 90 percent availability for individual modules when the system is equipped with one spare. The analysis also took into consideration the emergency by-pass provisions of the proposed regulation. The analysis showed that lower reliabilities would result in somewhat higher emissions and costs for both the partial and full control cases. Total coal capacity was slightly lower under full control and slightly higher under partial control. While it was postulated that the lower reliability assumption would produce greater adverse impacts on full control than on partial control options, the relative differences in impacts were found to be insignificant. Hence, the working group discarded the reliability issue as a major consideration in the analyzing of national impacts of full and partial control options. The Administrator still believes that the newer approach better reflects the performance of well designed, operated, and maintained FGD systems. However, in order to expedite the analyses, all subsequent alternatives were analyzed with an assumed system reliability of 100 percent.

Another adjustment to the analysis was the incorporation of dry SO_2 scrubbing systems. Dry scrubbers were assumed to be available for both new and retrofit applications. The costs of these systems were estimated by EPA's Office of Research and Development based on pilot plant studies and contract prices for systems currently under construction. Based on economic analysis, the use of dry scrubbers was assumed for low-sulfur coal (less than 1290 ng/J or 3 lb SO_2/million Btu) applications in which the control requirement was 70 percent or less. For higher sulfur content coals, wet scrubbers were assumed to be more economical. Hence, the scenarios characterized as using "dry" costs contain a mix of wet and dry technology whereas the "wet" scenarios assume wet scrubbing technology only.

Additional refinements included a change in the capital charge rate for pollution control equipment to conform to the Federal tax laws on depreciation, and the addition of 100 billion tons of coal reserves not previously accounted for in the model.

Finally, a number of less significant adjustments were made. These included adjustments in nuclear capacity to reflect a cancellation of a plant, consideration of oil consumption in transporting coal, and the adjustment of costs to 1978 dollars rather than 1975 dollars. It should be understood that all reported costs include the costs of complying with the proposed particulate matter standard and NO_x standards, as well as the sulfur dioxide alternatives. The model does not incorporate the Agency's PSD regulations nor forthcoming requirements to protect visibility.

Public Comments

Following the September proposal, a number of comments were received on the impact analysis. A great number focused on the model inputs, which were reviewed in detail by the joint working group. Members of the joint working group represented a spectrum of expertise (energy, jobs, environment, inflation, commerce). The following paragraphs discuss only those comments addressed to parts of the analysis which were not discussed in the preceding section.

One commenter suggested that the costs of complying with State Implementation Plan (SIP) regulations and prevention of significant deterioration requirements should not be charged to the standards. These costs are not charged to the standards in the analyses. Control requirements under PSD are based on site specific, case-by-case decisions for which the standards serves as a minimum level of control. Since these judgments cannot be forecasted accurately, no additional control was assumed by the model beyond the requirements of these standards. In addition, the cost of meeting the various SIP regulations was included as a base cost in all the scenarios modeled. Thus, any forecasted cost differences among alternative standards reflect differences in utility expenditures attributable to changes in the standards only.

Another commenter believed that the time horizon for the analysis (1990/1995) was too short since most plants on line at that time will not be subject to the revised standard. Beyond 1995, our data show that many of the power plants on line today will be approaching retirement age. As utilization of older capacity declines, demand will be picked up by newer, better controlled plants. As this replacement occurs, national SO_2 emissions will begin to decline. Based on this projection, the Administrator believes that the 1990–1995 time frame will represent the peak years for SO_2 emissions and is, therefore, the relevant time frame for this analysis.

Use of a higher general inflation rate was suggested by one commenter. A distinction must be made between general inflation rates and real cost escalation. Recognizing the uncertainty of future inflation rates, the EPA staff conducted the economic analysis in a manner that minimized reliance on this assumption. All construction, operating, and fuel costs were expressed as constant year dollars and therefore the analysis is not affected by the inflation rate. Only real cost escalation was included in the economic analysis. The inflation rates will have an impact on the present value discount rate chosen since this factor equals the inflation rate plus the real discount rate. However, this impact is constant across all scenarios and will have little impact on the conclusions of the analysis.

Another commenter opposed the presentation of economic impacts in terms of monthly residential electric bills, since this treatment neglects the impact of higher energy costs to industry. The Administrator agrees with this comment and has included indirect consumer impacts in the analysis. Based on results of previous analysis of the electric utility industry, about half of the total costs due to pollution control are felt as direct increases in residential electric bills. The increased costs also flow into the commercial and industrial sectors where they appear as increased costs of consumer goods. Since the Administrator is unaware of any evidence of a multiplier effect on these costs, straight cost pass through was assumed. Based on this analysis, the indirect consumer impacts (Table 5) were concluded to be equal to the monthly residential bills ("Economic and Financial Impacts of Federal Air and Water Pollution Controls on the Electric Utility Industry," EPA-230/3-76/013, May 1976).

One utility company commented that the model did not adequately simulate utility operation since it did not carry out hour-by-hour dispatch of generating units. The model dispatches by means of load duration curves which were developed for each of 35 demand regions across the United States. Development of these curves took into consideration representative daily load curves, traditional utility reserve margins, seasonal demand variations, and historical generation data. The Administrator believes that this approach is adequate for forecasting long-term impacts since it plans for meeting short-term peak demand requirements.

Summary of Results

The final results of the analyses are presented in Tables 2 through 5 and discussed below. For the three alternative standards presented, emission limits and percent reduction requirements are 30-day rolling averages, and each standard was analyzed with a particulate standard of 13 ng/J (0.03 lb/million Btu) and the proposed NO_x standards. The full control option was specified as a 520 ng/J (1.2 lb/million Btu) emission limit with a 90 percent reduction in potential SO_2 emissions. The other options are the same as full control except when the emissions to the atmosphere are reduced below 260 ng/J (0.6 lb/million Btu) in which case the minimum percent reduction requirement is reduced. The variable control option requires a 70 percent minimum reduction and the partial control option has a 33 percent minimum reduction requirement. The impacts of each option were forecast first assuming the use of wet scrubbers only and then assuming introduction of dry scrubbing technology. In contrast to the September proposal which focused on 1990 impacts, the analytical results presented today are for the year 1995. The Administrator believes that 1995 better represents the differences among alternatives since more new plants subject to the standard will be on line by 1995. Results of the 1990 analyses are available in the public record.

Wet Scrubbing Results

The projected SO_2 emissions from utility boilers are shown by plant type and geographic region in Tables 2 and 3. Table 2 details the 1995 national SO_2 emissions resulting from different plant types and age groups. These standards will reduce 1995 SO_2 emissions by about 3 million tons per year (13 percent) as compared to the current standards. The emissions from new plants directly affected by the standards are reduced by up to 55 percent. The emission reduction from new plants is due in part to lower emission rates and in part to reduced coal consumption predicted by the model. The reduced coal consumption in new plants results from the increased cost of constructing and operating new coal plants due to pollution controls. With these increased costs, the model predicts delays in construction of new plants and changes in the utilization of these plants after start-up. Reduced coal consumption by new plants is accompanied by higher utilization of existing plants and combustion turbines. This shift causes increased emissions from existing coal- and oil-fired plants, which partially offsets the emission reductions achieved by new plants subject to the standard.

Projections of 1995 regional SO_2 emissions are summarized in Table 3. Emissions in the East are reduced by about 10 to 13 percent as compared to predictions under the current standards, whereas Midwestern emissions are reduced only slightly. The smaller reductions in the Midwest are due to a slow growth of new coal-fired capacity.

In general, introductions of coal-fired capacity tends to reduce emissions since new coal plants replace old coal- and oil-fired units which have higher emission rates. The greatest emission reduction occurs in the West and West South Central regions where significant growth is expected and today's emissions are relatively low. For these two regions combined, the full control option reduces emissions by 40 percent from emission levels under the current standards, while the partial and variable options produce reductions of about 30 percent.

Table 4 illustrates the effect of the proposed standards on 1995 coal production, western coal shipped east, and utility oil and gas consumption. National coal production is predicted to triple by 1995 under all the alternative standards. This increased demand raises production in all regions of the country as compared to 1975 levels. Considering these major increases in national production, the small production variations among the alternatives are not large. Compared to production under the current standards, production is down somewhat in the West, Northern Great Plains, and Appalachia, while production is up in the Midwest. These shifts occur because of the reduced economic advantage of low-sulfur coals under the revised standards. While three times higher than 1975 levels, western coal shipped east is lower under all options than under the current standards.

Oil consumption in 1975 was 1.4 million barrels per day. The 3.1 million barrels per day figure for 1975 consumption in Table 4 includes utility natural gas consumption (equivalent of 1.7 million barrels per day) which the analysis assumed would be phased out by 1990. Hence, in 1995, the 1.4 million barrel per day projection under current standards reflects retirement of existing oil capacity and offsetting increases in consumption due to gas-to-oil conversions.

Oil consumption by utilities is predicted to increase under all the options. Compared to the current standards, increased consumption is 200,000 barrels per day under the partial and variable options and 400,000 barrels per day under full control. Oil consumption differences are due to the higher costs of new coal plants under these standards, which causes a shift to more generation from existing oil plants and combustion turbines. This shift in generation mix has important implications for the decision-making process, since the only assumed constraint to utility oil use was the price. For example, if national energy policy imposes other constraints which phase out or stabilize oil use for electric power generation, then the differences in both oil consumption and oil plant emissions (Table 2) across the various standards will be mitigated. Constraining oil consumption, however, will spread cost differences among standards.

The economic effects in 1995 are shown in Table 5. Utility capital expenditures increase under all options as compared to the $770 billion estimated to be required through 1995 in the absence of a change in the standard. The capital estimates in Table 5 are increments over the expenditures under the current standard and include both plant capital (for new capacity) and pollution control expenditures. As shown in Table 2, the model estimates total industry coal capacity to be about 17 GW (3 percent) greater under the non-uniform control options. The cost of this extra capacity makes the total utility capital expenditures higher under the partial and variable options, than under the full control option, even though pollution control capital is lower.

Annualized cost includes levelized capital charges, fuel costs, and operation and maintenance costs associated with utility equipment. All of the options cause an increase in annualized cost over the current standards. This increase ranges from a low of $3.2 billion for partial control to $4.1 billion for full control, compared to the total utility annualized costs of about $175 billion.

The average monthly bill is determined by estimating utility revenue requirements which are a function of capital expenditures, fuel costs, and operation and maintenance costs. The average bill is predicted to increase only slightly under any of the options, up to a maximum 3-percent increase shown for full control. Over half of the large total increase in the average monthly bill over 1975 levels ($25.50 per month) is due to a significant increase in the amount of electricity used by each customer. Pollution control expenditures, including those to meet the current standards, account for about 15 percent of the increase in the cost per kilowatt-hour while the remainder of the cost increase is due to capital intensive capacity expansion and real escalations in construction and fuel cost.

Indirect consumer impacts range from $1.10 to $1.60 per month depending on the alternative selected. Indirect consumer impacts reflect increases in consumer prices due to the increased energy costs in the commercial and industrial sectors.

The incremental costs per ton of SO_2 removal are also shown in Table 5. The figures are determined by dividing the change in annualized cost by the change in annual emissions, as compared to the current standards. These ratios are a measure of the cost effectiveness of the options, where lower ratios represent a more efficient resource allocation. All the options result in higher cost per ton than the current standards with the full control option being the most expensive.

Another measure of cost effectiveness is the average dollar-per-ton cost at the plant level. This figure compares total pollution control cost with total SO_2 emission reduction for a model plant. This average removal cost varies depending on the level of control and the coal sulfur content. The range for full control is from $325 per ton on high-sulfur coal to $1,700 per ton on low-sulfur coal. On low-sulfur coals, the partial control cost is $2,000 per ton, and the variable cost is $1,700 per ton.

The economic analyses also estimated the net present value cost of each option. Present value facilitates comparison of the options by reducing the streams of capital, fuel, and operation and maintenance expenses to one number. A present value estimate allows expenditures occurring at different times to be evaluated on a similar basis by discounting the expenditures back to a fixed year. The costs chosen for the present value analysis were the incremental utility revenue requirements relative to the current NSPS. These revenue requirements most closely represent the costs faced by consumers. Table 5 shows that the present value increment for 1995 capacity is $41 billion for full control, $37 billion for variable control, and $32 billion for partial control.

Dry Scrubbing Results

Tables 2 through 5 also show the impacts of the options under the assumption that dry SO_2 scrubbing systems penetrate the pollution control market. These analyses assume that utilities will install dry scrubbing systems for all applications where they are technologically feasible and less costly than wet systems. (See earlier discussion of assumptions.)

The projected SO_2 emissions from utility boilers are shown by plan type and geographic region in Tables 2 and 3. National emission projections are similar to the wet scrubbing results. Under the dry control assumption, however, the variable control option is predicted to have the lowest national emissions primarily due to lower oil plant emissions relative to the full control option. Partial control produces more emissions than variable control because of higher emissions from new plants. Compared to the current standards, regional emission impacts are also similar to the wet scrubbing projections. Full control results in the lowest emissions in the West, while variable control results in the lowest emissions in the East. Emissions in the Midwest and West South Central are relatively unaffected by the options.

Inspection of Tables 2 and 3 shows that with the dry control assumption the current standard, full control, and partial control cases produce slightly higher emissions than the corresponding wet control cases. This is due to several factors, the most important of which is a shift in the generation mix. This shift occurs because dry scrubbers have lower capital costs and higher variable costs than wet scrubbers and, therefor, the two systems have different effects on the plant utilization rates. The higher variable costs are due primarily to transportation charges on intermediate to low sulfur coal which must be used with dry scrubbers. The increased variable cost of dry controls alters the dispatch order of existing plants so that older, uncontrolled plants operate at relatively higher capacity factors than would occur under the wet scrubbing assumption, hence increasing total emissions. Another factor affecting emissions is utility coal selection which may be altered by differences in pollution control costs.

Table 4 shows the effect to the proposed standards on fuels in 1995. National coal production remains essentially the same whether dry or wet controls are assumed. However, the use of dry controls causes a slight reallocation in regional coal production, except under a full control option where dry controls cannot be applied to new plants. Under the variable and partial options Appalachian production increases somewhat due to greater demand for intermediate sulfur coals while Midwestern coal production declines slightly. The non-uniform options also result in a small shifting in the western regions with Northern Great Plains production declining and production in the rest of West increasing. The amount of western coal shipped east under the current standard is reduced from 122 million to 99 million tons (20% decrease) due to the increased use of eastern intermediate sulfur coals for dry scrubbing applications. Western coal shipped east is reduced further by the revised standards, to a low of 55 million tons under full control. Oil impacts under the dry control assumption are identical to the wet control cases, with full control resulting in increased consumption of 200 thousand barrels per day relative to the partial and variable options.

The 1995 economic effects of these standards are presented in Table 5. In general, the dry control assumption results in lower costs. However, when comparing the dry control costs to the wet control figures it must be kept in mind that the cost base for comparison, the current standards, is different under the dry control and wet control assumptions. Thus, while the uncremental costs of full control are higher under the dry scrubber assumption the total costs of meeting the standard is lower than if wet controls were used.

The economic impact figures show that when dry controls are assumed the cost savings associated with the variable and partial options is significantly increased over the wet control cases. Relative to full control the partial control option nets a savings of $1.4 billion in annualized costs which equals a $14 billion net present value savings. Variable control results in a $1.1 billion annualized cost savings which is a savings of $12 billion in net present value. These changes in utility costs affect the average residential bill only slightly, with partial control resulting in a savings of $.50 per month and variable control savings of $.40 per month on the average bill, relative to full control.

Conclusions

One finding that has been clearly demonstrated by the two years of analysis is that lower emission standards on new plants do not necessarily result in lower national SO_2 emissions when total emissions from the entire utility system are considered. There are two reasons for this finding. First, the lowest emissions tend to result from strategies that encourage the construction of new coal capacity. This capacity, almost regardless of the alternative analyzed, will be less polluting than the existing coal- or oil-fired capacity that it replaces. Second, the higher cost of operating the new capacity (due to higher pollution costs) may cause the newer, cleaner plants to be utilized less than they would be under a less stringent alternative. These situations are demonstrated by the analyses presented here.

The variable control option produces emissions that are equal to or lower than the other options under both the wet and dry scrubbing assumptions. Compared to full control, variable control is predicted to result in 12 GW to 17 GW more coal capacity. This additional capacity replaces dirtier existing plants and compensates for the slight increase in emissions from new plants subject to the standards, hence causing emissions to be less than or equal to full control emissions depending on scrubbing cost assumption (i.e., wet or dry). Partial control and variable control produce about the same coal capacity, but the additional 300 thousand ton emission reduction from new plants causes lower total emissions under the variable option. Regionally, all the options produce about the same emissions in the Midwest and West South Central regions. Full control produces 200 thousands tons less emissions in the West than the variable option and 300 thousand tons less than partial control. But the variable and partial options produce between 200 and 300 thousand tons less emissions in the East.

The variable and partial control options have a clear advantage over full control with respect to costs under both the wet and dry scrubbing assumptions. Under the dry assumption, which the Administrator believes represents the best prediction of utility behavior, variable control saves about $1.1 billion per year relative to full control and partial control saves an additional $0.3 billion.

All the options have similar impacts on coal production especially when considering the large increase predicted over 1975 production levels. With respect to oil consumption, however, the full control option causes a 200,000 barrel per day increase as compared to both the partial and variable options.

Based on these analyses, the Administrator has concluded that a non-uniform control strategy is best considering the environmental, energy, and economic impacts at both national and regional levels. Compared to other options analyzed, the variable control standard presented above achieves the lowest emissions in an efficient manner and will not disrupt local or regional coal markets. Moreover, this option avoids the 200 thousand barrel per day oil penalty which has been predicted under a number of control options. For these reasons, the Administrator believes that the variable control option provides the best balance of national environmental, energy, and economic objectives.

Table 1.—*Key Modeling Assumptions*

Assumption	
Growth rates	1975–1985: 4.8%/yr. 1985–1995: 4.0%.
Nuclear capacity	1985: 97 GW. 1990: 165. 1995: 228.
Oil prices ($ 1975)	1985: $12.90/bbl. 1990: $16.40. 1995: $21.00.
Coal transportation	1% per year real increase.
Coal mining labor costs	U.M.W. settlement and 1% real increase thereafter.
Capital charge rate	12.5% for pollution control expenditures.
Cost reporting basis	1978 dollars.
FGD costs	No change from phase 2 analysis except for the addition of dry scrubbing systems for certain applications.
Coal cleaning credit	5%–35% SO_2 reduction assumed for high sulfur bituminous coals only.
Bottom ash and fly ash content	No credit assumed.

Table 2.—*National 1995 SO_2 Emissions From Utility Boilers* [a]

[Million tons]

Plant category	Level of control [b]								
	1975 actual	Current standards		Full control		Partial control 33% minimum		Variable control 70% minimum	
		Wet [d]	*Dry* [e]	*Wet*	*Dry*	*Wet*	*Dry*	*Wet*	*Dry*
SIP/NSPS Plants [c]		15.5	15.8	16.0	16.2	15.9	16.2	16.0	16.1
New Plants [f]		7.1	7.0	3.1	3.1	3.6	3.4	3.3	3.1
Oil Plants		1.0	1.0	1.4	1.4	1.3	1.2	1.3	1.2
Total National Emissions	18.6	23.7	23.8	20.6	20.7	20.8	20.9	20.6	20.5
Total Coal Capacity (GW)	205	552	554	521	520	534	537	533	537
Sludge generated (million tons dry)		23	27	55	56	43	39	50	41

[a] Results of joint EPA/DOE analyses completed in May 1979 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.
[b] With 520 ng/J maximum emission limit.
[c] Plants subject to existing State regulations or the current NSPS of 1.2 lb SO_x/million BTU.
[d] Based on wet SO_2 scrubbing costs.
[e] Based on dry SO_2 scrubbing costs where applicable.
[f] Plants subject to the revised standards.

Table 3.—*Regional 1995 SO_2 Emissions From Utility Boilers* [a]

[Million tons]

	Level of control [b]								
	1975 actual	Current standards		Full control		Partial control 33% minimum		Variable control 70% minimum	
		Wet [c]	*Dry* [d]	*Wet*	*Dry*	*Wet*	*Dry*	*Wet*	*Dry*
Total National Emissions	18.6	23.7	23.8	20.6	20.7	20.8	20.9	20.6	20.5
Regional Emissions:									
East [e]		11.2	11.2	10.1	10.1	9.8	9.8	9.8	9.7
Midwest [f]		8.1	8.3	7.9	7.9	7.9	8.0	7.9	8.0
West South Central [g]		2.6	2.6	1.7	1.7	1.8	1.8	1.8	1.7
West [h]		1.7	1.7	0.9	0.9	1.2	1.2	1.1	1.1
Total Coal Capacity (GW)	205	552	554	521	520	534	537	533	537

[a] Results of joint EPA/DOE analyses completed in May 1979 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.
[b] With 520 ng/J maximum emission limit.
[c] Based on wet SO_2 scrubbing costs.
[d] Based on dry SO_2 scrubbing costs where applicable.
[e] New England, Middle Atlantic, South Atlantic, and East South Central Census Regions.
[f] East North Central and West North Central Census Regions.
[g] West South Central Census Region.
[h] Mountain and Pacific Census Regions.

Performance Testing

Particulate Matter

The final regulations require that Method 5 or 17 under 40 CFR Part 60, Appendix A, be used to determine compliance with the particulate matter emission limit. Particulate matter may be collected with Method 5 at an outstack filter temperature up to 160 C (320 F); Method 17 may be used when stack temperatures are less than 160 C (320 F). Compliance with the opacity standard in the final regulation is determined by means of Method 9, under 40 CFR Part 60, Appendix A. A transmissometer that meets Performance Specification 1 under 40 CFR Part 60, Appendix B is required.

Several comments were received which questioned the accuracy of Methods 5 and 17 when used to measure particulate matter at the level of the standard. The accuracy of Methods 5 and 17 is dependent on the amount of sample collected and not the concentration in the gas stream. To maintain an accuracy comparable to the accuracy obtained when testing for mass emission rates higher than the standard, it is necessary to sample for longer times. For this reason, the regulation requires a minimum sampling time of 120 minutes and a minimum sampling volume of 1.7 dscm (60 dscf).

Three comments raised the issue of potential interference of acid mist with the measurement of particulate matter. The Administrator recognized this issue prior to proposal of the regulations. In the preamble to the proposed regulations, the Administrator indicated that investigations would continue to determine the extent of the problem. A series of tests at an FGD-equipped facility burning 3-percent-sulfur coal indicate that the amount of sample collected using Method 5 precedures is temperature sensitive over the range of filter temperatures used (250° F to 380° F), with reduced weights at higher temperatures. Presumably, the decreased weight at higher filter temperatures reflect vaporization of acid mist. Recently received particulate emission data using Method 5 at 32° F for a second coal-fired power plant equipped with an electrostatic precipitator and an FGD system apparently conflicts with the data generated by EPA. For this plant, particulate matter was measured at 0.02 lbs/million Btu. It is not known what portion of this particulate matter, if any was attributable to sulfuric acid mist.

The intent of the particulate matter standard is to insure the installation, operation, and maintenance of a good

Table 4—*Impacts on Fuels in 1995*[a]

	1975 actual	Level of control[b]: Current standards		Full control		Partial control 33% minimum		Variable control 70% minimum	
		Wet[c]	*Dry*[d]	*Wet*	*Dry*	*Wet*	*Dry*	*Wet*	*Dry*
U.S. Coal Production (million tons):									
Appalachia	396	489	524	463	465	475	486	470	484
Midwest	151	404	391	487	488	456	452	465	450
Northern Great Plains	54	655	630	633	628	622	576	632	602
West	46	230	222	182	180	212	228	203	217
Total	647	1,778	1,767	1,765	1,761	1,765	1,742	1,770	1,752
Western Coal Shipped East (million tons)	21	122	99	59	55	68	59	71	70
Oil Consumpton by Power Plants (million bbl/day):									
Power Plants		1.2	1.2	1.6	1.6	1.4	1.4	1.4	1.4
Coal Transportation		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	3.1	1.4	1.4	1.8	1.8	1.6	1.6	1.6	1.6

[a] Results of EPA analyses completed in May 1979 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.
[b] With 520ng/J maximum emission limit.
[c] Based on wet SO_2 scrubbing costs.
[d] Based on dry SO_2 scrubbing where applicable.

Table 5.—*1995 Economic Impacts*[a]

[1978 dollars]

	Level of control[b]: Current standards		Full control		Partial control 33% minimum		Variable control 70% minimum	
	Wet[c]	*Dry*[d]	*Wet*	*Dry*	*Wet*	*Dry*	*Wet*	*Dry*
Average Monthly Residential Bills ($/month)	$53.00	$52.85	$54.50	$54.45	$54.15	$53.95	$54.30	$54.05
Indirect Consumer Impacts ($/month)			1.50	1.60	1.15	1.10	1.30	1.20
Incremental Utility Capital Expenditures, Cumulative 1976–1995 ($ billions)			4	5	6	−3	10	−1
Incremental Annualized Cost ($ billions)			4.1	4.4	3.2	3.0	3.6	3.3
Present Value of Incremental Utility Revenue Requirements ($ billions)			41	45	32	31	37	33
Incremental Cost of SO^2 Reduction ($/ton)			1,322	1,428	1,094	1,012	1,163	1,036

[a] Results of EPA analyses completed in May 1979 based on oil prices of $12.90, $16.40, and $21.00/bbl in the years 1985, 1990, and 1995, respectively.
[b] With 520 ng/J maximum emission limit.
[c] Based on wet SO_2 scrubbing costs.
[d] Based on dry SO_2 scrubbing costs where applicable.

emission control system. Since technology is not available for the control of sulfuric acid mist, which is condensed in the FGD system, the Administrator does not believe the particulate matter sample should include condensed acid mist. The final regulation, therefore, allows particulate matter testing for compliance between the outlet of the particulate matter control device and the inlet of a wet FGD system. EPA will continue to investigate revised procedures to minimize the measurement of acid mist by Methods 5 or 17 when used to measure particulate matter after the FGD system. Since technology is available to control particulate sulfate carryover from an FGD system, and the Administrator believes good mist eliminators should be included with all FGD systems, the regulations will be amended to require particulate matter measurement after the FGD system when revised procedures for Methods 5 or 17 are available.

SO_2 and NO_x

The final regulation requires that compliance with the sulfur dioxide and nitrogen oxides standards be determined by using continuous monitoring systems (CMS) meeting Performance Specifications 2 and 3, under 40 CFR Part 60, Appendix B. Data from the CMS are used to calculate a 30-day rolling average emission rate and percentage reduction (sulfur dioxide only) for the initial performance test required under 40 CFR 60.8. At the end of each boiler operating day after the initial performance test a new 30-day rolling average emission rate for sulfur dioxide and nitrogen oxides and an average percent reduction for sulfur dioxide are determined. The final regulations specify the minimum amount of data that must be obtained for each 30 successive boiler operating days but requires the calculation of the average emission rate and percentage reduction based on all available data. The minimum data requirements can be satisfied by using the Reference Methods or other approved alternative methods when the CMS, or components of the system, are inoperative.

The final regulation requires operation of the continuous monitors at all times, including periods of startup, shutdown, malfunction (NO_x only), and emergency conditions (SO_2 only), except for those periods when the CMS is inoperative because of malfunctions, calibration or span checks.

The proposed regulations would have required that compliance be based on the emission rate and percent reduction (sulfur dioxide only) for each 24-hour period of operation. Continual determination of compliance with the proposed standard would have necessitated that each source owner or operator install redundant CMS or conduct manual testing in the event of CMS malfunction.

Comments on the proposed testing requirements for sulfur dioxide and nitrogen oxides indicated that CMS could not operate without malfunctions; therefore, every facility would require redundant CMS. One commenter calculated that seven CMS would be needed to provide the required data. Comments also questioned the practicality and feasibility of obtaining around-the-clock emissions data by means of manual testing in the event of CMS malfunction. The commenter stated that the need for immediate backup testing using manual methods would require a stand-by test team at all times and that extreme weather conditions or other circumstances could often make it impossible for the test team to obtain the required data. The Administrator agrees with these comments and has redefined the data requirements to reflect the performance that can be achieved with one well-maintained CMS. The final requirements are designed to eliminate the need for redundant CMS and minimize the possibility that manual testing will be necessary, while assuring acquisition of sufficient data to document compliance.

Compliance with the emission limitations for sulfur dioxide and nitrogen oxides and the percentage reduction for sulfur dioxide is determined from all available hourly averages, except for periods of startup, shutdown, malfunction or emergency conditions for each 30 successive boiler operating days. Minimum data requirements have been established for hourly averages, for 24-hour periods, and for the 30 successive boiler operating days. These minimum requirements eliminate the need for redundant CMS and minimize the need for testing using manual sampling techniques. The minimum requirements apply separately to inlet and outlet monitoring systems.

The regulation allows calculation of hourly averages for the CMS using two or more of the required four data points. This provision was added to accommodate those monitors for which span and calibration checks and minor repairs might require more than 15 minutes.

For any 24-hour period, emissions data must be obtained for a minimum of 75 percent of the hours during which the affected facility is operated (including startup, shutdown, malfunctions or emergency conditions). This provision was added to allow additional time for CMS calibrations and to correct minor CMS problems, such as a lamp failure, a plugged probe, or a soiled lens. Statistical analyses of data obtained by EPA show that there is no significant difference (at the 95 percent confidence interval) between 24-hour means based on 75 percent of the data and those based on the full data set.

To provide time to correct major CMS malfunctions and minimize the possibility that supplemental testing will be needed, a provision has been added which allows the source owner or operator to demonstrate compliance if the minimum data for each 24-hour period has been obtained for 22 of the 30 successive boiler operating days. This provision is based on EPA studies that have shown that a single pair of CMS pollutant and diluent monitors can be made available in excess of 75 percent of the time and several comments showing CMS availability in excess of 90 percent of the time.

In the event a CMS malfunction would prevent the source owner or operator from meeting the minimum data requirements, the regulation requires that the reference methods or other procedures approved by the Administrator be used to supplement the data. The Administrator believes, however, that a single properly designed, maintained, and operated CMS with trained personnel and an appropriate inventory of spare parts can achieve the monitoring requirements with currently available CMS equipment. In the event that an owner or operator fails to meet the minimum data requirements, a procedure is provided which may be used by the Administrator to determine compliance with the SO_2 and NO_x standards. The procedure is provided to reduce potential problems that might arise if an owner or operation is unable to meet the minimum data requirements or attempts to manipulate the acquisition of data so as to avoid the demonstration of noncompliance. The Administrator believes that an owner or operator should not be able to avoid a finding of noncompliance with the emission standards solely by noncompliance with the minimum data requirements. Penalties related only to failure to meet the minimum data requirements may be less than those for failure to meet the emission standards and may not provide as great an incentive to maintain compliance with the regulations.

The procedure involves the calculation of standard deviations for the available inlet SO_2 monitoring data and the available outlet SO_2 and NO_x monitoring data and assumes the data are normally distributed. The standard deviation of the inlet monitoring data for SO_2 is used to calculate the upper confidence limit of the inlet emission rate at the 95 percent confidence interval. The upper confidence limit of the inlet emission rate is used to determine the potential combustion concentration and the allowable emission rate. The standard deviation of the outlet monitoring data for SO_2 and NO_x are used to calculate the lower confidence limit of the outlet emission rates at the 95 percent confidence interval. The lower confidence limit of the outlet emission rate is compared with the allowable emission rate to determine compliance. If the lower confidence limit of the outlet emission rate is greater than the allowable emission rate for the reporting period, the Administrator will conclude that noncompliance has occurred.

The regulations require the source owner or operator who fails to meet the minimum data requirements to perform the calculations required by the added procedure, and to report the results of the calculations in the quarterly report. The Administrator may use this information for determining the compliance status of the affected facility.

It is emphasized that while the regulations permit a determination of the compliance status of a facility in the absence of data reflecting some periods of operation, an owner and operator is required by 40 CFR 60.11(d) to continue to operate the facility at all times so as to minimize emissions consistent with good engineering practice. Also, the added procedure which allows for a determination of compliance when less than the minimum monitoring data have been obtained does not exempt the source owner or operator from the minimum data requirements. Exemption from the minimum data requirements could allow the source owner to circumvent the standard, since the added procedure assumes random variations in emission rates.

One commenter suggested that operating data be used in place of CMS data to demonstrate compliance. The Administrator does not believe, however, that the demonstration of compliance can be based on operating data alone. Consideration was given to the reporting of operating parameters during those periods when emissions data have not been obtained. This alternative was rejected because it would mean that the source owner or operator would need to record the operating parameters at all times, and would impose an administrative burden on source owners or operators in compliance with the emission monitoring requirements. The regulation requires the owner or operator to certify that the emission control systems have been kept in operation during periods when emissions data have not been obtained.

Several commenters indicated that CMS were not sufficiently accurate to allow for a determination of compliance. One commenter provided calculations showing that the CMS could report an FGD efficiency ranging from 77.5 to 90 percent, with the scrubber operating at an efficiency of 85 percent. The analysis submitted by the commenter is theoretically possible for any single data point generated by the CMS. For the 30-day averaging periods, however, random variations in individual data points are not significant. The criterion of importance in showing compliance for this longer averaging time is the difference between the mean values measured by the CMS and the reference methods. EPA is developing quality assurance procedures, which will require a periodic demonstration that the mean emission rates measured by the CMS demonstrates a consistent and reproducible relationship with the mean emission rates measured by the reference methods or acceptable modifications of these methods.

A specific comment received on the monitoring requirements questioned the need to respan the CMS for sulfur dioxide when the sulfur content of the fuel changed by 0.5 percent. The intent of this requirement was to assure that a change in fuel sulfur content would not result in emissions exceeding the range of the CMS. This requirement has been deleted on the premise that the source owner or operator will initiate his own procedures to protect himself against loss of data.

Several comments were also received concerning detailed technical items contained in Performance Specifications 2 and 3. One comment, for example, suggested that a single "relative accuracy" specification be used for the entire CMS, as opposed to separate values for the pollutant and diluent monitors. Another comment questioned the performance specification on instrument response time, while still other comments raised questions on calibration procedures. EPA is in the process of revising Performance Specifications 2 and 3 to respond to these, and other questions. The current performance specifications, however, are adequate for the determination of compliance.

Fuel Pretreatment

The final regulation allows credit for fuel pretreatment to remove sulfur or increase heat content. Fuel pretreatment credits are determined in accordance with Method 19. This means that coal or oil may be treated before firing and the sulfur removed may be credited toward meeting the SO_2 percentage reduction requirement. The final fuel pretreatment provisions are the same as those proposed.

Most all commenters on this issue supported the fuel pretreatment crediting procedures proposed by EPA. Several commenters requested that credit also be given for sulfur removed in the coal bottom ash and fly ash. This is allowed under the final regulation and was also allowed under the proposal in the optional "as-fired" fuel sampling procedures under the SO_2 emission monitoring requirements. By monitoring SO_2 emissions (ng/J, lb/million Btu) with an as-fired fuel sampling system located upstream of coal pulverizers and with an in-stack continuous SO_2 monitoring system downstream of the FGD system, sulfur removal credits are combined for the coal pulverizer, bottom ash, fly ash and FGD system into one removal efficiency. Other alternative sampling procedures may also be submitted to the Administrator for approval.

Several commenters indicated that they did not understand the proposed fuel pretreatment crediting procedure for refined fuel oil. The Administrator intended to allow fuel pretreatment credits for all fuel oil desulfurization processes used in preparation of utility boiler fuels. Thus, the input and output from oil desulfurization processes (e.g., hydrotreatment units) that are used to pretreat utility boiler fuels used in determining pretreatment credits. If desulfurized oil is blended with undesulfurized oil, fuel pretreatment credits are prorated based on heat input of oils blended. The Administrator believes that the oil input to the desulfurizer should be considered the input for credit determination and not the well head crude oil or input oil to the refinery. Refining of crude oil results in the separation of the base stock into various density fractions which range from lighter products such as naphtha and distillate oils. Most of the sulfur from the crude oil is bound to the heavier residual oils which may have a sulfur content of twice the input crude oil. The residual oils can be upgraded to a lower sulfur utility steam generator fuel through the use of desulfurization technology (such as hydrodesulfurization). The Administrator believes that it is appropriate to give full fuel pretreatment credit for hydrotreatment units and not to penalize hydrodesulfurization units which are used to process high-sulfur residual oils. Thus, the input to the hydrodesulfurization unit is used to determine oil pretreatment credits and not the lower sulfur refinery input crude. This procedure will allow full credit for residual oil hydrodesulfurization units.

In relation to fuel pretreatment credits for coal, commenters requested that sampling be allowed prior to the initial coal breaker. Under the final standards, coal sampling may be conducted at any location (either before or after the initial coal breaker). It is desirable to sample coal after the initial breaker because the smaller coal volume and coal size will reduce sampling requirements under Method 19. If sampling were conducted before the initial breaker, rock removed by the coal breaker would not result in any additional sulfur removal credit. Coal samples are analyzed to determine potential SO_2 emissions in ng/J (lb/million Btu) and any removal of rock or other similar reject material will not change the potential SO_2 emission rate (ng/J; lb/million Btu).

An owner or operator of an affected facility who elects to use fuel pretreatment credits is responsible for insuring that the EPA Method 19 procedures are followed in determining SO_2 removal credit for pretreatment equipment.

Miscellaneous

Establishment of standards of performance for electric utility steam generating units was preceded by the Administrator's determination that these sources contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare (36 FR 5931), and by proposal of regulations on September 19, 1978 (43 FR 42154). In addition, a preproposal public hearing (May 25–26, 1977) and a postproposal public hearing (December 12–13, 1978) was held after notification was given in the **Federal Register**. Under section 117 of the Act, publication of these regulations was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

Standards of performance for new fossil-fuel-fired stationary sources established under section 111 of the Clean Air Act reflect:

Application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. [section 111(a)(1)]

Although there may be emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act requires (or has potential for requiring) the imposition of a more stringent emission standard in several situations.

For example, applicable costs do not play as prominent a role in determining the "lowest achievable emission rate" for new or modified sources located in nonattainment areas, i.e., those areas where statutorily-mandated health and welfare standards are being violated. In this respect, section 173 of the Act requires that a new or modified source constructed in an area that exceeds the National Ambient Air Quality Standard (NAAQS) must reduce emissions to the level that reflects the "lowest achievable emission rate" (LAER), as defined in section 171(3), for such source category. The statute defines LAER as that rate of emission which reflects:

(A) The most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or

(B) The most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent.

In no event can the emission rate exceed any applicable new source performance standard [section 171(3)].

A similar situation may arise under the prevention of significant deterioration of air quality provisions of the Act (Part C). These provisions require that certain sources [referred to in section 169(1)] employ "best available control technology" [as defined in section 169(3)] for all pollutants regulated under the Act. Best available control technology (BACT) must be determined on a case-by-case basis, taking energy, environmental and economic impacts, and other costs into account. In no event may the application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 (or 112) of the Act.

In all events, State implementation plans (SIP's) approved or promulgated under section 110 of the Act must provide for the attainment and maintenance of National Ambient Air Quality Standards designed to protect public health and welfare. For this purpose, SIP's must in some cases require greater emission reductions than those required by standards of performance for new sources.

Finally, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Accordingly, new sources may in some cases be subject to limitations more stringent than EPA's standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

Under EPA's sunset policy for reporting requirements in regulations, the reporting requirements in this regulation will automatically expire five years from the date of promulgation unless the Administrator takes affirmative action to extend them. Within the five year period, the Administrator will review these requirements.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for revisions determined by the Administrator to be substantial. The Administrator has determined that these revisions are substantial and has prepared an economic impact assessment and included the required information in the background information documents.

Dated: June 1, 1979.

Douglas M. Costle,
Administrator.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

In 40 CFR Part 60, § 60.8 of Subpart A is revised, the heading and § 60.40 of Subpart D are revised, a new Subpart Da is added, and a new reference method is added to Appendix A as follows:

1. Section 60.8(d) and § 60.8(f) are revised as follows:

§ 60.8 Performance tests.

* * * * *

(d) The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present.

* * * * *

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

2. The heading for Subpart D is revised to read as follows:

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971

3. Section 60.40 is amended by adding paragraph (d) as follows:

§ 60.40 Applicability and designation of affected facility.

* * * * *

(d) Any facility covered under Subpart Da is not covered under This Subpart.

(Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a)).)

4. A new Subpart Da is added as follows:

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18,1978

Sec.

Authority: Sec. 111, 301(a) of the Clean Air Act as amended (42 U.S.C. 7411, 7601(a)), and additional authority as noted below.

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978

§ 60.40a Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction or modification is commenced after September 18, 1978.

(b) This subpart applies to electric utility combined cycle gas turbines that are capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel in the steam generator. Only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to Subpart GG.)

(c) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels, shall not bring that unit under the applicability of this subpart.

(d) Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that unit under the applicability of this subpart.

§ 60.41a Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

"Steam generating unit" means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

"Electric utility steam generating unit" means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

"Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

"Subbituminous coal" means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-66.

"Lignite" means coal that is classified as lignite A or B according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-66.

"Coal refuse" means waste products of coal mining, physical coal cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

"Potential combustion concentration" means the theoretical emissions (ng/J, lb/million Btu heat input) that would result from combustion of a fuel in an uncleaned state 9without emission control systems) and:

(a) For particulate matter is:

(1) 3,000 ng/J (7.0 lb/million Btu) heat input for solid fuel; and

(2) 75 ng/J (0.17 lb/million Btu) heat input for liquid fuels.

(b) For sulfur dioxide is determined under § 60.48a(b).

(c) For nitrogen oxides is:

(1) 290 ng/J (0.67 lb/million Btu) heat input for gaseous fuels;

(2) 310 ng/J (0.72 lb/million Btu) heat input for liquid fuels; and

(3) 990 ng/J (2.30 lb/million Btu) heat input for solid fuels.

"Combined cycle gas turbine" means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a steam generating unit.

"Interconnected" means that two or more electric generating units are electrically tied together by a network of power transmission lines, and other power transmission equipment.

"Electric utility company" means the largest interconnected organization, business, or governmental entity that generates electric power for sale (e.g., a holding company with operating subsidiary companies).

"Principal company" means the electric utility company or companies which own the affected facility.

"Neighboring company" means any one of those electric utility companies with one or more electric power interconnections to the principal company and which have geographically adjoining service areas.

"Net system capacity" means the sum of the net electric generating capability (not necessarily equal to rated capacity) of all electric generating equipment owned by an electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) plus firm contractual purchases that are interconnected to the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

"System load" means the entire electric demand of an electric utility company's service area interconnected with the affected facility that has the malfunctioning flue gas desulfurization system plus firm contractual sales to other electric utility companies. Sales to other electric utility companies (e.g., emergency power) not on a firm contractual basis may also be included in the system load when no available system capacity exists in the electric utility company to which the power is supplied for sale.

"System emergency reserves" means an amount of electric generating capacity equivalent to the rated capacity of the single largest electric generating unit in the electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) which is interconnected with the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

"Available system capacity" means the capacity determined by subtracting the system load and the system emergency reserves from the net system capacity.

"Spinning reserve" means the sum of the unutilized net generating capability of all units of the electric utility company that are synchronized to the power distribution system and that are capable of immediately accepting additional load. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

"Available purchase power" means the lesser of the following:

(a) The sum of available system capacity in all neighboring companies.

(b) The sum of the rated capacities of the power interconnection devices between the principal company and all neighboring companies, minus the sum of the electric power load on these interconnections.

(c) The rated capacity of the power transmission lines between the power interconnection devices and the electric generating units (the unit in the principal company that has the malfunctioning flue gas desulfurization system and the unit(s) in the neighboring company supplying replacement electrical power) less the electric power load on these transmission lines.

"Spare flue gas desulfurization system module" means a separate system of sulfur dioxide emission control equipment capable of treating an amount of flue gas equal to the total amount of flue gas generated by an affected facility when operated at maximum capacity divided by the total number of nonspare flue gas desulfurization modules in the system.

"Emergency condition" means that period of time when:

(a) The electric generation output of an affected facility with a malfunctioning flue gas desulfurization system cannot be reduced or electrical output must be increased because:

(1) All available system capacity in the principal company interconnected with the affected facility is being operated, and

(2) All available purchase power interconnected with the affected facility is being obtained, or

(b) The electric generation demand is being shifted as quickly as possible from an affected facility with a malfunctioning flue gas desulfurization system to one or more electrical generating units held in reserve by the principal company or by a neighboring company, or

(c) An affected facility with a malfunctioning flue gas desulfurization system becomes the only available unit to maintain a part or all of the principal company's system emergency reserves and the unit is operated in spinning reserve at the lowest practical electric generation load consistent with not causing significant physical damage to the unit. If the unit is operated at a higher load to meet load demand, an emergency condition would not exist unless the conditions under (a) of this definition apply.

"Electric utility combined cycle gas turbine" means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

"Potential electrical output capacity" is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100-MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33-MW potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

"Anthracite" means coal that is classified as anthracite according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-66.

"Solid-derived fuel" means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquified coal, and gasified coal.

"24-hour period" means the period of time between 12:01 a.m. and 12:00 midnight.

"Resource recovery unit" means a facility that combusts more than 75 percent non-fossil fuel on a quarterly (calendar) heat input basis.

"Noncontinental area" means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

"Boiler operating day" means a 24-hour period during which fossil fuel is combusted in a steam generating unit for the entire 24 hours.

§ 60.42a Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain particulate matter in excess of:

(1) 13 ng/J (0.03 lb/million Btu) heat input derived from the combustion of solid, liquid, or gaseous fuel;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(b) On and after the date the particulate matter performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

§ 60.43a Standard for sulfur dioxide.

(a) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases which contain sulfur dioxide in excess of:

(1) 520 ng/J (1.20 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/million Btu) heat input.

(b) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section), any gases which contain sulfur dioxide in excess of:

(1) 340 ng/J (0.80 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/million Btu) heat input.

(c) On and after the date on which the initial performance test required to be conducted under § 60.8 is complete, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid solvent refined coal (SRC–I) any gases which contain sulfur dioxide in excess of 520 ng/J (1.20 lb/million Btu) heat input and 15 percent of the potential combustion concentration (85 percent reduction) except as provided under paragraph (f) of this section; compliance with the emission limitation is determined on a 30-day rolling average basis and compliance with the percent reduction requirement is determined on a 24-hour basis.

(d) Sulfur dioxide emissions are limited to 520 ng/J (1.20 lb/million Btu) heat input from any affected facility which:

(1) Combusts 100 percent anthracite,

(2) Is classified as a resource recovery facility, or

(3) Is located in a noncontinental area and combusts solid fuel or solid-derived fuel.

(e) Sulfur dixoide emissions are limited to 340 ng/J (0.80 lb/million Btu) heat input from any affected facility which is located in a noncontinental area and combusts liquid or gaseous fuels (excluding solid-derived fuels).

(f) The emission reduction requirements under this section do not apply to any affected facility that is operated under an SO_2 commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.45a.

(g) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.

(h) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

(1) If emissions of sulfur dioxide to the atmosphere are greater than 260 ng/J (0.60 lb/million Btu) heat input

$E_{SO_2} = [340\,x + 520\,y]/100$ and
$P_{SO_2} = 10$ percent

(2) If emissions of sulfur dioxide to the atmosphere are equal to or less than 260 ng/J (0.60 lb/million Btu) heat input:

$E_{SO_2} = [340\,x + 520\,y]/100$ and
$P_{SO_2} = [90\,x + 70\,y]/100$

where:

E_{SO_2} is the prorated sulfur dioxide emission limit (ng/J heat input),
P_{SO_2} is the percentage of potential sulfur dioxide emission allowed (percent reduction required $= 100 - P_{SO_2}$),
x is the percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels)
y is the percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels)

§ 60.44a Standard for nitrogen oxides.

(a) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under paragraph (b) of this section, any gases which contain nitrogen oxides in excess of the following emission limits, based on a 30-day rolling average.

(1) NO_x Emission Limits—

Fuel type	Emission limit ng/J (lb/million Btu) heat input	
Gaseous Fuels:		
Coal-derived fuels	210	(0.50)
All other fuels	86	(0.20)
Liquid Fuels:		
Coal-derived fuels	210	(0.50)
Shale oil	210	(0.50)
All other fuels	130	(0.30)
Solid Fuels:		
Coal-derived fuels	210	(0.50)
Any fuel containing more than 25%, by weight, coal refuse	Exempt from NO_x standards and NO_x monitoring requirements	
Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace	340	(0.80)
Lignite not subject to the 340 ng/J heat input emission limit	260	(0.60)
Subbituminous coal	210	(0.50)
Bituminous coal	260	(0.60)
Anthracite coal	260	(0.60)
All other fuels	260	(0.60)

(2) NO_x reduction requirements—

Fuel type	Percent reduction of potential combustion concentration
Gaseous fuels	25%
Liquid fuels	30%
Solid fuels	65%

(b) The emission limitations under paragraph (a) of this section do not apply to any affected facility which is combusting coal-derived liquid fuel and is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.45a.

(c) When two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$E_{NO_x} = [86\,w + 130\,x + 210\,y + 260\,z]/100$

where:

E_{NO_x} is the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (ng/J heat input);
w is the percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;
x is the percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;
y is the percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard; and
z is the percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard.

§ 60.45a Commercial demonstration permit.

(a) An owner or operator of an affected facility proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. The Administrator will issue a commercial demonstration permit in accordance with paragraph (e) of this section. Commercial demonstration permits may be issued only by the Administrator, and this authority will not be delegated.

(b) An owner or operator of an affected facility that combusts solid solvent refined coal (SRC–I) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 emission reduction requirements under § 60.43a(c) but must, as a minimum, reduce SO_2 emissions to 20 percent of the potential combustion concentration (80 percent reduction) for each 24-hour period of steam generator operation and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis.

(c) An owner or operator of a fluidized bed combustion electric utility steam generator (atmospheric or pressurized) who is issued a commercial demonstration permit by the Administrator is not subject to the SO_2 emission reduction requirements under § 60.43a(a) but must, as a minimum, reduce SO_2 emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis.

(d) The owner or operator of an affected facility that combusts coal-derived liquid fuel and who is issued a commercial demonstration permit by the Administrator is not subject to the applicable NO_x emission limitation and percent reduction under § 60.44a(a) but must, as a minimum, reduce emissions to less than 300 ng/J (0.70 lb/million Btu) heat input on a 30-day rolling average basis.

(e) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category, and the total equivalent MW electrical generation capacity for all commercial demonstration plants may not exceed 15,000 MW.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Solid solvent refined coal (SRC I)	SO_2	6,000–10,000
Fluidized bed combustion (atmospheric)	SO_2	400–3,000
Fluidized bed combustion (pressurized)	SO_2	400–1,200
Coal liquification	NO_x	750–10,000
Total allowable for all technologies		15,000

§ 60.46a Compliance provisions.

(a) Compliance with the particulate matter emission limitation under § 60.42a(a)(1) constitutes compliance with the percent reduction requirements for particulate matter under § 60.42a(a)(2) and (3).

(b) Compliance with the nitrogen oxides emission limitation under § 60.44a(a) constitutes compliance with the percent reduction requirements under § 60.44a(a)(2).

(c) The particulate matter emission standards under § 60.42a and the nitrogen oxides emission standards under § 60.44a apply at all times except during periods of startup, shutdown, or malfunction. The sulfur dioxide emission standards under § 60.43a apply at all times except during periods of startup, shutdown, or when both emergency conditions exist and the procedures under paragraph (d) of this section are implemented.

(d) During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by:

(1) Operating all operable flue gas desulfurization system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,

(2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any sulfur dioxide emission reduction or which would have suffered significant physical damage if they had remained in operation, and

(3) Designing, constructing, and operating a spare flue gas desulfurization system module for an affected facility larger than 365 MW (1,250 million Btu/hr) heat input (approximately 125 MW electrical output capacity). The Administrator may at his discretion require the owner or operator within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements under paragraph (a), (b), (d), (e), and (i) under § 60.43a for any period of operation lasting from 24 hours to 30 days when:

(i) Any one flue gas desulfurization module is not operated,

(ii) The affected facility is operating at the maximum heat input rate,

(iii) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and

(iv) The owner or operator has given the Administrator at least 30 days notice of the date and period of time over which the demonstration will be performed.

(e) After the initial performance test required under § 60.8, compliance with the sulfur dioxide emission limitations and percentage reduction requirements under § 60.43a and the nitrogen oxides emission limitations under § 60.44a is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.

(f) For the initial performance test required under § 60.8, compliance with the sulfur dioxide emission limitations and percent reduction requirements under § 60.43a and the nitrogen oxides emission limitation under § 60.44a is based on the average emission rates for sulfur dioxide, nitrogen oxides, and percent reduction for sulfur dioxide for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(g) Compliance is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO_x only), or emergency conditions (SO_2 only). Compliance with the percentage reduction requirement for SO_2 is determined based on the average inlet and average outlet SO_2 emission rates for the 30 successive boiler operating days.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under § 60.47a of this subpart, compliance of the affected facility with the emission requirements under §§ 60.43a and 60.44a of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in sections 6.0 and 7.0 of Reference Method 19 (Appendix A).

§ 60.47a Emission monitoring.

(a) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere, except where gaseous fuel is the only fuel combusted. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions, except where natural gas is the only fuel combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.

(2) For a facility which qualifies under the provisions of § 60.43a(d), sulfur dioxide emissions are only monitored as discharged to the atmosphere.

(3) An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 (Appendix A) may be used to determine

potential sulfur dioxide emissions in place of a continuous sulfur dioxide emission monitor at the inlet to the sulfur dioxide control device as required under paragraph (b)(1) of this section.

(c) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere.

(d) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

(e) The continuous monitoring systems under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(f) When emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using other monitoring systems as approved by the Administrator or the reference methods as described in paragraph (h) of this section to provide emission data for a minimum of 18 hours in at least 22 out of 30 successive boiler operating days.

(g) The 1-hour averages required under paragraph § 60.13(h) are expressed in ng/J (lbs/million Btu) heat input and used to calculate the average emission rates under § 60.46a. The 1-hour averages are calculated using the data points required under § 60.13(b). At least two data points must be used to calculate the 1-hour averages.

(h) Reference methods used to supplement continuous monitoring system data to meet the minimum data requirements in paragraph § 60.47a(f) will be used as specified below or otherwise approved by the Administrator.

(1) Reference Methods 3, 6, and 7, as applicable, are used. The sampling location(s) are the same as those used for the continuous monitoring system.

(2) For Method 6, the minimum sampling time is 20 minutes and the minimum sampling volume is 0.02 dscm (0.71 dscf) for each sample. Samples are taken at approximately 60-minute intervals. Each sample represents a 1-hour average.

(3) For Method 7, samples are taken at approximately 30-minute intervals. The arithmetic average of these two consective samples represent a 1-hour average.

(4) For Method 3, the oxygen or carbon dioxide sample is to be taken for each hour when continuous SO_2 and NO_x data are taken or when Methods 6 and 7 are required. Each sample shall be taken for a minimum of 30 minutes in each hour using the integrated bag method specified in Method 3. Each sample represents a 1-hour average.

(5) For each 1-hour average, the emissions expressed in ng/J (lb/million Btu) heat input are determined and used as needed to achieve the minimum data requirements of paragraph (f) of this section.

(i) The following procedures are used to conduct monitoring system performance evaluations under § 60.13(c) and calibration checks under § 60.13(d).

(1) Reference method 6 or 7, as applicable, is used for conducting performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems.

(2) Sulfur dioxide or nitrogen oxides, as applicable, is used for preparing calibration gas mixtures under performance specification 2 of appendix B to this part.

(3) For affected facilities burning only fossil fuel, the span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides is determined as follows:

Fossil fuel	Span value for nitrogen oxides (ppm)
Gas	500
Liquid	500
Solid	1,000
Combination	500 (x+y)+1,000z

where:
x is the fraction of total heat input derived from gaseous fossil fuel,
y is the fraction of total heat input derived from liquid fossil fuel, and
z is the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under paragraph (b)(3) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to the sulfur dioxide control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414).)

§ 60.48a Compliance determination procedures and methods.

(a) The following procedures and reference methods are used to determine compliance with the standards for particulate matter under § 60.42a.

(1) Method 3 is used for gas analysis when applying method 5 or method 17.

(2) Method 5 is used for determining particulate matter emissions and associated moisture content. Method 17 may be used for stack gas temperatures less than 160 C (320 F).

(3) For Methods 5 or 17, Method 1 is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(4) For Method 5, the probe and filter holder heating system in the sampling train is set to provide a gas temperature no greater than 160°C (32°F).

(5) For determination of particulate emissions, the oxygen or carbon-dioxide sample is obtained simultaneously with each run of Methods 5 or 17 by traversing the duct at the same sampling location. Method 1 is used for selection of the number of traverse points except that no more than 12 sample points are required.

(6) For each run using Methods 5 or 17, the emission rate expressed in ng/J heat input is determined using the oxygen or carbon-dioxide measurements and particulate matter measurements obtained under this section, the dry basis F_c-factor and the dry basis emission rate calculation procedure contained in Method 19 (Appendix A).

(7) Prior to the Administrator's issuance of a particulate matter reference method that does not experience sulfuric acid mist interference problems, particulate matter emissions may be sampled prior to a wet flue gas desulfurization system.

(b) The following procedures and methods are used to determine compliance with the sulfur dioxide standards under § 60.43a.

(1) Determine the percent of potential combustion concentration (percent PCC) emitted to the atmosphere as follows:

(i) *Fuel Pretreatment (% R_f):* Determine the percent reduction achieved by any fuel pretreatment using the procedures in Method 19 (Appendix A). Calculate the average percent reduction for fuel pretreatment on a quarterly basis using fuel analysis data. The determination of percent R_f to calculate the percent of potential combustion concentration emitted to the atmosphere is optional. For purposes of determining compliance with any percent reduction requirements under § 60.43a, any reduction in potential SO_2 emissions resulting from the following processes may be credited:

(A) Fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.),

(B) Coal pulverizers, and

(C) Bottom and flyash interactions.

(ii) *Sulfur Dioxide Control System (% R_g):* Determine the percent sulfur dioxide reduction achieved by any sulfur dioxide control system using emission rates measured before and after the control system, following the procedures in Method 19 (Appendix A); or, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19 (Appendix A). When the "as fired" fuel monitor is used, the percent reduction is calculated using the average emission rate from the sulfur dioxide control device and the average SO_2 input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

(iii) *Overall percent reduction (% R_o):* Determine the overall percent reduction using the results obtained in paragraphs (b)(1) (i) and (ii) of this section following the procedures in Method 19 (Appendix A). Results are calculated for each 30-day period using the quarterly average percent sulfur reduction determined for fuel pretreatment from the previous quarter and the sulfur dioxide reduction achieved by a sulfur dioxide control system for each 30-day period in the current quarter.

(iv) *Percent emitted (% PCC):* Calculate the percent of potential combustion concentration emitted to the atmosphere using the following equation: Percent PCC=100−Percent R_o

(2) Determine the sulfur dioxide emission rates following the procedures in Method 19 (Appendix A).

(c) The procedures and methods outlined in Method 19 (Appendix A) are used in conjunction with the 30-day nitrogen-oxides emission data collected under § 60.47a to determine compliance with the applicable nitrogen oxides standard under § 60.44.

(d) Electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19 (Appendix A). The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 (Appendix A) calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

§ 60.49a Reporting requirements.

(a) For sulfur dioxide, nitrogen oxides, and particulate matter emissions, the performance test data from the initial performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For sulfur dioxide and nitrogen oxides the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average sulfur dioxide and nitrogen oxide emission rates (ng/J or lb/million Btu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) Percent reduction of the potential combustion concentration of sulfur dioxide for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or dilutent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO_x only), emergency conditions (SO_2 only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by § 60.47a is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of § 60.46a(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (n_o) and inlet emission rates (n_i) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates (s_o) and inlet emission rates (s_i) as applicable.

(3) The lower confidence limit for the mean outlet emission rate ($E_o{}^*$) and the upper confidence limit for the mean inlet emission rate ($E_i{}^*$) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate ($E_o{}^*$) and the allowable emission rate (E_{std}) as applicable.

(d) If any standards under § 60.43a are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating if emergency conditions existed and requirements under § 60.46a(d) were met during each period, and

(2) Listing the following information:

(i) Time periods the emergency condition existed;

(ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;

(iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;

(iv) Percent reduction in emissions achieved;

(v) Atmospheric emission rate (ng/J) of the pollutant discharged; and

(vi) Actions taken to correct control system malfunction.

(e) If fuel pretreatment credit toward the sulfur dioxide emission standard under § 60.43a is claimed, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the

provisions of § 60.48a and Method 19 (Appendix A); and

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

(f) For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(g) The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

(h) For the purposes of the reports required under § 60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under § 60.42a(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(i) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414).)

4. Appendix A to part 60 is amended by adding new reference Method 19 as follows:

Appendix A—Reference Methods

* * * * *

Method 19. Determination of Sulfur Dioxide Removal Efficiency and Particulate, Sulfur Dioxide and Nitrogen Oxides Emission Rates From Electric Utility Steam Generators

1. *Principle and Applicability*

1.1 *Principle.*

1.1.1 Fuel samples from before and after fuel pretreatment systems are collected and analyzed for sulfur and heat content, and the percent sulfur dioxide (ng/Joule, lb/million Btu) reduction is calculated on a dry basis. (Optional Procedure.)

1.1.2 Sulfur dioxide and oxygen or carbon dioxide concentration data obtained from sampling emissions upstream and downstream of sulfur dioxide control devices are used to calculate sulfur dioxide removal efficiencies. (Minimum Requirement.) As an alternative to sulfur dioxide monitoring upstream of sulfur dioxide control devices, fuel samples may be collected in an as-fired condition and analyzed for sulfur and heat content. (Optional Procedure.)

1.1.3 An overall sulfur dioxide emission reduction efficiency is calculated from the efficiency of fuel pretreatment systems and the efficiency of sulfur dioxide control devices.

1.1.4 Particulate, sulfur dioxide, nitrogen oxides, and oxygen or carbon dioxide concentration data obtained from sampling emissions downstream from sulfur dioxide control devices are used along with F factors to calculate particulate, sulfur dioxide, and nitrogen oxides emission rates. F factors are values relating combustion gas volume to the heat content of fuels.

1.2 *Applicability.* This method is applicable for determining sulfur removal efficiencies of fuel pretreatment and sulfur dioxide control devices and the overall reduction of potential sulfur dioxide emissions from electric utility steam generators. This method is also applicable for the determination of particulate, sulfur dioxide, and nitrogen oxides emission rates.

2. *Determination of Sulfur Dioxide Removal Efficiency of Fuel Pretreatment Systems*

2.1 *Solid Fossil Fuel.*

2.1.1 *Sample Increment Collection.* Use ASTM D 2234[1], Type I, conditions A, B, or C, and systematic spacing. Determine the number and weight of increments required per gross sample representing each coal lot according to Table 2 or Paragraph 7.1.5.2 of ASTM D 2234[1]. Collect one gross sample for each raw coal lot and one gross sample for each product coal lot.

2.1.2 *ASTM Lot Size.* For the purpose of Section 2.1.1, the product coal lot size is defined as the weight of product coal produced from one type of raw coal. The raw coal lot size is the weight of raw coal used to produce one product coal lot. Typically, the lot size is the weight of coal processsed in a 1-day (24 hours) period. If more than one type of coal is treated and produced in 1 day, then gross samples must be collected and analyzed for each type of coal. A coal lot size equaling the 90-day quarterly fuel quantity for a specific power plant may be used if representative sampling can be conducted for the raw coal and product coal.

Note.—Alternate definitions of fuel lot sizes may be specified subject to prior approval of the Administrator.

2.1.3 *Gross Sample Analysis.* Determine the percent sulfur content (%S) and gross calorific value (GCV) of the solid fuel on a dry basis for each gross sample. Use ASTM 2013 [1] for sample preparation, ASTM D 3177 [1] for sulfur analysis, and ASTM D 3173 [1] for moisture analysis. Use ASTM D 3176 [1] for gross calorific value determination.

2.2 *Liquid Fossil Fuel.*

2.2.1 *Sample Collection.* Use ASTM D 270 [1] following the practices outlined for continuous sampling for each gross sample representing each fuel lot.

2.2.2 *Lot Size.* For the purposes of Section 2.2.1, the weight of product fuel from one pretreatment facility and intended as one shipment (ship load, barge load, etc.) is defined as one product fuel lot. The weight of each crude liquid fuel type used to produce one product fuel lot is defined as one inlet fuel lot.

Note.— Alternate definitions of fuel lot sizes may be specified subject to prior approval of the Administrator.

Note.— For the purposes of this method, raw or inlet fuel (coal or oil) is defined as the fuel delivered to the desulfurization pretreatment facility or to the steam generating plant. For pretreated oil the input oil to the oil desulfurization process (e.g. hydrotreatment emitted) is sampled.

2.2.3 *Sample Analysis.* Determine the percent sulfur content (%S) and gross calorific value (GCV). Use ASTMD 240 [1] for the sample analysis. This value can be assumed to be on a dry basis.

[1] Use the most recent revision or designation of the ASTM procedure specified.

[1] Use the most recent revision or designation of the ASTM procedure specified.

2.3 *Calculation of Sulfur Dioxide Removal Efficiency Due to Fuel Pretreatment.* Calculate the percent sulfur dioxide reduction due to fuel pretreatment using the following equation:

$$\%R_f = 100 \left[1 - \frac{\%S_o/GCV_o}{\%S_i/GCV_i} \right]$$

Where:

$\%R_f$ = Sulfur dioxide removal efficiency due pretreatment; percent.

$\%S_o$ = Sulfur content of the product fuel lot on a dry basis; weight percent.

$\%S_i$ = Sulfur content of the inlet fuel lot on a dry basis; weight percent.

GCV_o = Gross calorific value for the outlet fuel lot on a dry basis; kJ/kg (Btu/lb).

GCV_i = Gross calorific value for the inlet fuel lot on a dry basis; kJ/kg (Btu/1b).

Note.—If more than one fuel type is used to produce the product fuel, use the following equation to calculate the sulfur contents per unit of heat content of the total fuel lot, %S/GCV:

$$\%S/GCV = \sum_{k=1}^{n} Y_k(\%S_k/GCV_k)$$

Where:

Y_k = The fraction of total mass input derived from each type, k, of fuel.

$\%S_k$ = Sulfur content of each fuel type, k, on a dry basis; weight percent.

GCV_k = Gross calorific value for each fuel type, k, on a dry basis; kJ/kg (Btu/lb).

n = The number of different types of fuels.

3. *Determination of Sulfur Removal Efficiency of the Sulfur Dioxide Control Device*

3.1 *Sampling.* Determine SO_2 emission rates at the inlet and outlet of the sulfur dioxide control system according to methods specified in the applicable subpart of the regulations and the procedures specified in Section 5. The inlet sulfur dioxide emission rate may be determined through fuel analysis (Optional, see Section 3.3.)

3.2. *Calculation.* Calculate the percent removal efficiency using the following equation:

$$\%R_{g(m)} = 100 \times (1.0 - \frac{E_{SO_2o}}{E_{SO_2i}})$$

Where:

$\%R_g$ = Sulfur dioxide removal efficiency of the sulfur dioxide control system using inlet and outlet monitoring data; percent.

$E_{SO\ o}$ = Sulfur dioxide emission rate from the outlet of the sulfur dioxide control system; ng/J (lb/million Btu).

$E_{SO\ i}$ = Sulfur dioxide emission rate to the outlet of the sulfur dioxide control system; ng/J (lb/million Btu).

3.3 *As-fired Fuel Analysis (Optional Procedure).* If the owner or operator of an electric utility steam generator chooses to determine the sulfur dioxide imput rate at the inlet to the sulfur dioxide control device through an as-fired fuel analysis in lieu of data from a sulfur dioxide control system inlet gas monitor, fuel samples must be collected in accordance with applicable paragraph in Section 2. The sampling can be conducted upstream of any fuel processing, e.g., plant coal pulverization. For the purposes of this section, a fuel lot size is defined as the weight of fuel consumed in 1 day (24 hours) and is directly related to the exhaust gas monitoring data at the outlet of the sulfur dioxide control system.

3.3.1 *Fuel Analysis.* Fuel samples must be analyzed for sulfur content and gross calorific value. The ASTM procedures for determining sulfur content are defined in the applicable paragraphs of Section 2.

3.3.2 *Calculation of Sulfur Dioxide Input Rate.* The sulfur dioxide imput rate determined from fuel analysis is calculated by:

$$I_s = \frac{2.0(\%S_f)}{GCV} \times 10^7 \text{ for S. I. units.}$$

$$I_s = \frac{2.0(\%S_f)}{GCV} \times 10^4 \text{ for English units.}$$

Where:

I_s = Sulfur dioxide input rate from as-fired fuel analysis, ng/J (lb/million Btu).

$\%S_f$ = Sulfur content of as-fired fuel, on a dry basis; weight percent.

GCV = Gross calorific value for as-fired fuel, on a dry basis; kJ/kg (Btu/lb).

3.3.3 *Calculation of Sulfur Dioxide Emission Reduction Using As-fired Fuel Analysis.* The sulfur dioxide emission reduction efficiency is calculated using the sulfur imput rate from paragraph 3.3.2 and the sulfur dioxide emission rate, E_{SO_2}, determined in the applicable paragraph of Section 5.3. The equation for sulfur dioxide emission reduction efficiency is:

$$\%R_{g(f)} = 100 \times (1.0 - \frac{E_{SO_2}}{I_s})$$

Where:

$\%R_{g(f)}$ = Sulfur dioxide removal efficiency of the sulfur dioxide control system using as-fired fuel analysis data; percent.

E_{SO_2} = Sulfur dioxide emission rate from sulfur dioxide control system; ng/J (lb/million Btu).

I_s = Sulfur dioxide input rate from as-fired fuel analysis; ng/J (lb/million Btu).

4. Calculation of Overall Reduction in Potential Sulfur Dioxide Emission

4.1 The overall percent sulfur dioxide reduction calculation uses the sulfur dioxide concentration at the inlet to the sulfur dioxide control device as the base value. Any sulfur reduction realized through fuel cleaning is introduced into the equation as an average percent reduction, $\%R_f$.

4.2 Calculate the overall percent sulfur reduction as:

$$\%R_o = 100[1.0 - (1.0 - \frac{\%R_f}{100})(1.0 - \frac{\%R_g}{100})]$$

Where:

$\%R_o$ = Overall sulfur dioxide reduction; percent.

$\%R_f$ = Sulfur dioxide removal efficiency of fuel pretreatment from Section 2; percent. Refer to applicable subpart for definition of applicable averaging period.

$\%R_g$ = Sulfur dioxide removal efficiency of sulfur dioxide control device either O_2 or CO_2 - based calculation or calculated from fuel analysis and emission data, from Section 3; percent. Refer to applicable subpart for definition of applicable averaging period.

5. Calculation of Particulate, Sulfur Dioxide, and Nitrogen Oxides Emission Rates

5.1 *Sampling.* Use the outlet SO_2 or O_2 or CO_2 concentrations data obtained in Section 3.1. Determine the particulate, NO_x, and O_2 or CO_2 concentrations according to methods specified in an applicable subpart of the regulations.

5.2 *Determination of an F Factor.* Select an average F factor (Section 5.2.1) or calculate an applicable F factor (Section 5.2.2.). If combined fuels are fired, the selected or calculated F factors are prorated using the procedures in Section 5.2.3. F factors are ratios of the gas volume released during combustion of a fuel divided by the heat content of the fuel. A dry F factor (F_d) is the ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted; a wet F factor (F_w) is the ratio of the volume of wet flue gases generated to the calorific value of the fuel combusted; and the carbon F factor (F_c) is the ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted. When pollutant and oxygen concentrations have been determined in Section 5.1, wet or dry F factors are used. (F_w) factors and associated emission calculation procedures are not applicable and may not be used after wet scrubbers; (F_c) or (F_d) factors and associated emission calculation procedures are used after wet scrubbers.) When pollutant and carbon dioxide concentrations have been determined in Section 5.1, F_c factors are used.

5.2.1 *Average F Factors.* Table 1 shows average F_d, F_w, and F_c factors (scm/J, scf/million Btu) determined for commonly used fuels. For fuels not listed in Table 1, the F factors are calculated according to the procedures outlined in Section 5.2.2 of this section.

5.2.2 *Calculating an F Factor.* If the fuel burned is not listed in Table 1 or if the owner or operator chooses to determine an F factor rather than use the tabulated data, F factors are calculated using the equations below. The sampling and analysis procedures followed in obtaining data for these calculations are subject to the approval of the Administrator and the Administrator should be consulted prior to data collection.

For SI Units:

$$F_d = \frac{227.0(\%H) + 95.7(\%C) + 35.4(\%S) + 8.6(\%N) - 28.5(\%O)}{GCV}$$

$$F_w = \frac{347.4(\%H)+95.7(\%C)+35.4(\%S)+8.6(\%N)-28.5(\%O)+13.0(\%H_2O)^{**}}{GCV_w}$$

$$F_c = \frac{20.0(\%C)}{GCV}$$

For English Units:

$$F_d = \frac{10^6[5.57(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)]}{GCV}$$

$$F_w = \frac{10^6[5.57(\%H)+1.53(\%C)+0.57(\%S)+0.14(\%N)-0.46(\%O)+0.21(\%H_2O)^{**}]}{GCV_w}$$

$$F_c = \frac{10^6[0.321(\%C)]}{GCV}$$

** The $\%H_2O$ term may be omitted if %H and %O include the unavailable hydrogen and oxygen in the form of H_2O.

Where:

F_d, F_w, and F_c have the units of scm/J, or scf/million Btu; %H, %C, %S, %N, %O, and %H_2O are the concentrations by weight (expressed in percent) of hydrogen, carbon, sulfur, nitrogen, oxygen, and water from an ultimate analysis of the fuel; and GCV is the gross calorific value of the fuel in kJ/kg or Btu/lb and consistent with the ultimate analysis. Follow ASTM D 2015* for solid fuels, D 240* for liquid fuels, and D 1826* for gaseous fuels as applicable in determining GCV.

5.2.3 *Combined Fuel Firing F Factor.* For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F_d, F_w, or F_c factors determined by Sections 5.2.1 or 5.2.2 of this section shall be prorated in accordance with applicable formula as follows:

$$F_d = \sum_{k=1}^{n} x_k F_{dk} \quad \text{or}$$

$$F_w = \sum_{k=1}^{n} x_k F_{wk} \quad \text{or}$$

$$F_c = \sum_{k=1}^{n} x_k F_{ck}$$

Where:

x_k=The fraction of total heat input derived from each type of fuel, K.

n=The number of fuels being burned in combination.

5.3 *Calculation of Emission Rate.* Select from the following paragraphs the applicable calculation procedure and calculate the particulate, SO_2, and NO_x emission rate. The values in the equations are defined as:

E=Pollutant emission rate, ng/J (lb/million Btu).

C=Pollutant concentration, ng/scm (lb/scf).

Note.—It is necessary in some cases to convert measured concentration units to other units for these calculations.

Use the following table for such conversions:

Conversion Factors for Concentration

From—	To—	Multiply by—
g/scm	ng/scm	10^9
mg/scm	ng/scm	10^6
lb/scf	ng/scm	1.602×10^{13}
ppm(SO_2)	ng/scm	2.660×10^6
ppm(NO_x)	ng/scm	1.912×10^6
ppm/(SO_2)	lb/scf	1.660×10^{-7}
ppm/(NO_x)	lb/scf	1.194×10^{-7}

5.3.1 *Oxygen-Based F Factor Procedure.*

5.3.1.1 *Dry Basis.* When both percent oxygen (%O_{2d}) and the pollutant concentration (C_d) are measured in the flue gas on a dry basis, the following equation is applicable:

$$E = C_d F_d \left[\frac{20.9}{20.9 - \%O_{2d}}\right]$$

5.3.1.2 *Wet Basis.* When both the percent oxygen (%O_{2w}) and the pollutant concentration (C_w) are measured in the flue gas on a wet basis, the following equations are applicable: (Note: F_w factors are not applicable after wet scrubbers.)

$$\text{(a)} \quad E = C_w F_w \left[\frac{20.9}{20.9(1 - B_{wa}) - \%O_{2w}}\right]$$

Where:

B_{wa}=Proportion by volume of water vapor in the ambient air.

In lieu of actual measurement, B_{wa} may be estimated as follows:

Note.—The following estimating factors are selected to assure that any negative error introduced in the term:

$$\left(\frac{20.9}{20.9(1 - B_{wa}) - \%O_{2ws}}\right)$$

will not be larger than −1.5 percent. However, positive errors, or over-estimation of emissions, of as much as 5 percent may be introduced depending upon the geographic location of the facility and the associated range of ambient mositure.

(i) B_{wa}=0.027. This factor may be used as a constant value at any location.

(ii) B_{wa}=Highest monthly average of B_{wa} which occurred within a calendar year at the nearest Weather Service Station.

(iii) B_{wa}=Highest daily average of B_{wa} which occurred within a calendar month at the nearest Weather Service Station, calculated from the data for the past 3 years. This factor shall be calculated for each month and may be used as an estimating factor for the respective calendar month.

$$\text{(b)} \quad E = C_w F_d \left[\frac{20.9}{20.9(1 - B_{ws}) - \%O_{2w}}\right]$$

Where:

B_{ws}=Proportion by volume of water vapor in the stack gas.

5.3.1.3 *Dry/Wet Basis.* When the pollutant concentration (C_w) is measured on a wet basis and the oxygen concentration (%O_{2d}) or measured on a dry basis, the following equation is applicable:

$$E = \left[\frac{C_w F_d}{(1 - B_{ws})}\right] \left[\frac{20.9}{20.9 - \%O_{2d}}\right]$$

When the pollutant concentration (C_d) is measured on a dry basis and the oxygen concentration (%O_{2d}) is measured on a wet basis, the following equation is applicable:

$$E = C_d F_d \frac{20.9}{20.9 - \left(\frac{\%O_{2w}}{(1 - B_{ws})}\right)}$$

5.3.2 *Carbon Dioxide-Based F Factor Procedure.*

5.3.2.1 *Dry Basis.* When both the percent carbon dioxide (%CO_{2d}) and the pollutant concentration (C_d) are measured in the flue gas on a dry basis, the following equation is applicable:

$$E = C_d F_c \left(\frac{100}{\%CO_{2d}}\right)$$

5.3.2.2 *Wet Basis.* When both the percent carbon dioxide (%CO_{2w}) and the pollutant concentration (C_w) are measured on a wet basis, the following equation is applicable:

$$E = C_w F_c \left(\frac{100}{\%CO_{2w}}\right)$$

5.3.2.3 *Dry/Wet Basis.* When the pollutant concentration (C_w) is measured on a wet basis and the percent carbon dioxide (%CO_{2d}) is measured on a dry basis, the following equation is applicable:

$$E = \left[\frac{C_w F_c}{(1 - B_{ws})}\right] \left[\frac{100}{\%CO_{2d}}\right]$$

When the pollutant concentration (C_d) is measured on a dry basis and the precent carbon dioxide (%CO_{2w}) is measured on a wet basis, the following equation is applicable:

$$E = C_d (1 - B_{ws}) F_c \left(\frac{100}{\%CO_{2w}}\right)$$

5.4 *Calculation of Emission Rate from Combined Cycle-Gas Turbine Systems.* For gas turbine-steam generator combined cycle systems, the emissions from supplemental fuel fired to the steam generator or the percentage reduction in potential (SO_2) emissions cannot be determined directly. Using measurements from the gas turbine exhaust (performance test, subpart GG) and the combined exhaust gases from the steam generator, calculate the emission rates for these two points following the appropriate paragraphs in Section 5.3.

Note.—F_w factors shall not be used to determine emission rates from gas turbines because of the injection of steam nor to calculate emission rates after wet scrubbers; F_d or F_c factor and associated calculation procedures are used to combine effluent emissions according to the procedure in Paragraph 5.2.3.

The emission rate from the steam generator is calculated as:

$$E_{sg} = \frac{E_c - X_{gt} E_{gt}}{X_{sg}}$$

Where:

- E_{sg} = Pollutant emission rate from steam generator effluent, ng/J (lb/million Btu).
- E_c = Pollutant emission rate in combined cycle effluent; ng/J (lb/million Btu).
- E_{gt} = Pollutant emission rate from gas turbine effluent; ng/J (lb/million Btu).
- X_{sg} = Fraction of total heat input from supplemental fuel fired to the steam generator.
- X_{gt} = Fraction of total heat input from gas turbine exhaust gases.

Note.—The total heat input to the steam generator is the sum of the heat input from supplemental fuel fired to the steam generator and the heat input to the steam generator from the exhaust gases from the gas turbine.

5.5 *Effect of Wet Scrubber Exhaust, Direct-Fired Reheat Fuel Burning.* Some wet scrubber systems require that the temperature of the exhaust gas be raised above the moisture dew-point prior to the gas entering the stack. One method used to accomplish this is directfiring of an auxiliary burner into the exhaust gas. The heat required for such burners is from 1 to 2 percent of total heat input of the steam generating plant. The effect of this fuel burning on the exhaust gas components will be less than ±1.0 percent and will have a similar effect on emission rate calculations. Because of this small effect, a determination of effluent gas constituents from direct-fired reheat burners for correction of stack gas concentrations is not necessary.

Table 19-1.—*F Factors for Various fuels* [c]

Fuel type	F_d dscm/J	F_d dscf/10^6 Btu	F_w wscm/J	F_w wscf/10^6 Btu	F_c scm/J	F_c scf/10^6 Btu
Coal:						
Anthracite [a]	2.71×10^{-7}	(10100)	2.83×10^{-7}	(10540)	0.530×10^{-7}	(1970)
Bituminous [a]	2.63×10^{-7}	(9780)	2.86×10^{-7}	(10640)	0.484×10^{-7}	(1800)
Lignite	2.65×10^{-7}	(9860)	3.21×10^{-7}	(11950)	0.513×10^{-7}	(1910)
Oil [b]	2.47×10^{-7}	(9190)	2.77×10^{-7}	(10320)	0.383×10^{-7}	(1420)
Gas:						
Natural	2.43×10^{-7}	(8710)	2.85×10^{-7}	(10610)	0.287×10^{-7}	(1040)
Propane	2.34×10^{-7}	(8710)	2.74×10^{-7}	(10200)	0.321×10^{-7}	(1190)
Butane	2.34×10^{-7}	(8710)	2.79×10^{-7}	(10390)	0.337×10^{-7}	(1250)
Wood	2.48×10^{-7}	(9240)			0.492×10^{-7}	(1830)
Wood Bark	2.58×10^{-7}	(9600)			0.497×10^{-7}	(1850)

[a] As classified according to ASTM D 388-66.
[b] Crude, residual, or distillate.
[c] Determined at standard conditions: 20° C (68° F) and 760 mm Hg (29.92 in. Hg).

6. *Calculation of Confidence Limits for Inlet and Outlet Monitoring Data*

6.1 *Mean Emission Rates.* Calculate the mean emission rates using hourly averages in ng/J (lb/million Btu) for SO_2 and NO_x outlet data and, if applicable, SO_2 inlet data using the following equations:

$$E_o = \frac{\Sigma x_o}{n_o}$$

$$E_i = \frac{\Sigma x_i}{n_i}$$

Where:

- E_o = Mean outlet emission rate; ng/J (lb/million Btu).
- E_i = Mean inlet emission rate; ng/J (lb/million Btu).
- x_o = Hourly average outlet emission rate; ng/J (lb/million Btu).
- x_i = Hourly average in let emission rate; ng/j (lb/million Btu).
- n_o = Number of outlet hourly averages available for the reporting period.
- n_i = Number of inlet hourly averages available for reporting period.

6.2 *Standard Deviation of Hourly Emission Rates.* Calculate the standard deviation of the available outlet hourly average emission rates for SO_2 and NO_x and, if applicable, the available inlet hourly average emission rates for SO_2 using the following equations:

$$s_o = \left(\sqrt{\frac{1}{n_o} - \frac{1}{720}}\right)\left(\sqrt{\frac{\Sigma (E_o - x_o)^2}{n_o - 1}}\right)$$

$$s_i = \left(\sqrt{\frac{1}{n_i} - \frac{1}{720}}\right)\left(\sqrt{\frac{\Sigma (E_i - x_i)^2}{n_i - 1}}\right)$$

Where:

- s_o = Standard deviation of the average outlet hourly average emission rates for the reporting period; ng/J (lb/million Btu).
- s_i = Standard deviation of the average inlet hourly average emission rates for the reporting period; ng/J (lb/million Btu).

6.3 *Confidence Limits.* Calculate the lower confidence limit for the mean outlet emission rates for SO_2 and NO_x and, if applicable, the upper confidence limit for the mean inlet emission rate for SO_2 using the following equations:

$$E_o^* = E_o - t_{0.95} s_o$$
$$E_i^* = E_i + t_{0.95} s_i$$

Where:

- E_o^* = The lower confidence limit for the mean outlet emission rates; ng/J (lb/million Btu).
- E_i^* = The upper confidence limit for the mean inlet emission rate; ng/J (lb/million Btu).
- $t_{0.95}$ = Values shown below for the indicated number of available data points (n):

n	Values for $t_{0.95}$
2	6.31
3	2.42
4	2.35
5	2.13
6	2.02
7	1.94
8	1.89
9	1.86
10	1.83
11	1.81
12–16	1.77
17–21	1.73
22–26	1.71
27–31	1.70
32–51	1.68
52–91	1.67
92–151	1.66
152 or more	1.65

The values of this table are corrected for n-1 degrees of freedom. Use n equal to the number of hourly average data points.

7. *Calculation to Demonstrate Compliance When Available Monitoring Data Are Less Than the Required Minimum*

7.1 *Determine Potential Combustion Concentration (PCC) for SO_2.*

7.1.1 When the removal efficiency due to fuel pretreatment (% R_f) is included in the overall reduction in potential sulfur dioxide emissions (% R_o) and the "as-fired" fuel analysis is not used, the potential combustion concentration (PCC) is determined as follows:

$$PCC = E_i^* + 2\left(\frac{\%\,S_i}{GCV_i} - \frac{\%\,S_o}{GCV_o}\right)10^7;\ ng/J$$

$$PCC = E_i^* + 2\left(\frac{\%\,S_i}{GCV_i} - \frac{\%\,S_o}{GCV_o}\right)10^4;\ lb/million\ Btu.$$

Where:

$\left(\frac{\%\,S_i}{GCV_i} - \frac{\%\,S_o}{GCV_o}\right)$ = Potential emissions removed by the pretreatment process, using the fuel parameters defined in section 2.3; ng/J (lb/million Btu).

7.1.2 When the "as-fired" fuel analysis is used and the removal efficiency due to fuel pretreatment (% R_f) is not included in the overall reduction in potential sulfur dioxide emissions (% R_o), the potential combustion concentration (PCC) is determined as follows:

$PCC = I_s$

Where:

I_s = The sulfur dioxide input rate as defined in section 3.3

7.1.3 When the "as-fired" fuel analysis is used and the removal efficiency due to fuel pretreatment (% R_f) is included in the overall reduction (% R_o), the potential combustion concentration (PCC) is determined as follows:

$$PCC = I_s + 2\left(\frac{\%\,S_i}{GCV_i} - \frac{\%\,S_o}{GCV_o}\right)10^7;\ ng/J$$

$$PCC = I_s + 2\left(\frac{\%\,S_i}{GCV_i} - \frac{\%\,S_o}{GCV_o}\right)10^4;\ lb/million\ Btu.$$

7.1.4 When inlet monitoring data are used and the removal efficiency due to fuel pretreatment (% R_f) is not included in the overall reduction in potential sulfur dioxide emissions (% R_o), the potential combustion concentration (PCC) is determined as follows:

$PCC = E_i^*$

Where:

E_i^* = The upper confidence limit of the mean inlet emission rate, as determined in section 6.3.

7.2 *Determine Allowable Emission Rates (E_{std}).*

7.2.1 *NO_x*. Use the allowable emission rates for NO_x as directly defined by the applicable standard in terms of ng/J (lb/million Btu).

7.2.2 *SO_2*. Use the potential combustion concentration (PCC) for SO_2 as determined in section 7.1, to determine the applicable emission standard. If the applicable standard is an allowable emission rate in ng/J (lb/million Btu), the allowable emission rate is used as E_{std}. If the applicable standard is an allowable percent emission, calculate the allowable emission rate (E_{std}) using the following equation:

$E_{std} = \%\,PCC/100$

Where:

% PCC = Allowable percent emission as defined by the applicable standard; percent.

7.3 *Calculate E_o^*/E_{std}.* To determine compliance for the reporting period calculate the ratio:

E_o^*/E_{std}

Where:

E_o^* = The lower confidence limit for the mean outlet emission rates, as defined in section 6.3; ng/J (lb/million Btu).

E_{std} = Allowable emission rate as defined in section 7.2; ng/J (lb/million Btu).

If E_o^*/E_{std} is equal to or less than 1.0, the facility is in compliance; if E_o^*/E_{std} is greater than 1.0, the facility is not in compliance for the reporting period.

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